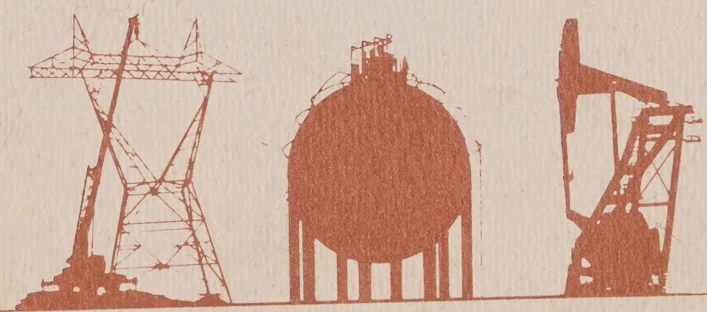
National Energy Board

CANADIAN ENERGY

Supply and Demand 1990 - 2010



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CANADIAN ENERGY
SUPPLY AND DEMAND 1990-2010

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Foreword

The National Energy Board ("NEB" or "the Board") was created by an Act of Parliament in 1959. The Board's regulatory powers under the *National Energy Board Act* ("the Act") include the authorizing of the export of oil, gas and electricity and of the construction of interprovincial and international pipelines and international power lines, and the setting of just and reasonable tolls for pipelines under federal jurisdiction. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception, the Board has prepared and maintained projections of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. In a July, 1987 decision in which the Board adopted a Market-Based Procedure for regulating natural gas exports, the Board indicated its intention to continue to produce and publish these *Canadian Energy Supply and Demand* reports as one component of the ongoing monitoring part of the Market-Based Procedure. The latest of these reports was issued in the fall of 1988.

Since September 1988, there has been evolution in energy markets and government policies in both Canada and the United States, the major market for our exports of energy. In addition, environmental issues, which relate in large measure to the production and use of energy, have become more prominent in Canada and internationally.

In May 1990, the Board announced that its staff would update the September 1988 Report.

In conducting its analysis, Board staff made use of an informal consultation process, which it has found to be an effective way of obtaining views regarding its projections of energy supply and demand. This process also permits staff to obtain the advice of interested parties at reduced cost to them and to the Board.

Although the Board did not request formal submissions, any party interested in providing its views was invited to do so. Board staff prepared two information packages which were made available for public comment. The first, issued in May, described preliminary views on assumptions, and the second, issued in the fall, provided preliminary projections. Comments received were made publicly available in the Board's library in Ottawa and at its Calgary office. Two rounds of consultations were held. The first concerned methodology and assumptions as to, for example, world oil prices, natural gas and electricity pricing and trade, and economic growth and environmental issues; the second, preliminary projections. These consultations encompassed governments, industry, and other interested parties in both Canada and the United States.

In light of the consultations and the written comments received, Board staff developed the revised projections contained in this report, including the assumptions and analysis underlying them. We thank all those who generously gave of their time and expertise to this endeavour; their input was most useful.

These reports are issued by the Board for the information of the public. A number of parties raised concerns over the use of *Canadian Energy Supply and Demand* reports in the Board's regulatory proceedings, and questioned whether these reports are an official reflection of Board views. The Board therefore wishes to clarify its views in this regard.

The Board recognizes that parties have not had the opportunity to examine or test the findings and conclusions contained in these reports in a public forum. Material from them may be used as part of the evidentiary record in particular regulatory proceedings to the extent that any party chooses to rely on such material, just as it could rely on any public document. In such a case, the material in effect is adopted by the party introducing it. In this respect, there has been no change in the way in which the report is used by the Board.

This report provides *detailed* information on the assumptions, methodology and results of the analysis of the supply and demand for energy in Canada, and of the associated emissions of certain gases. There is also a companion *Summary* report. Copies of this report or the *Summary* report can be obtained by contacting the Board at 311-6th Ave. S.W., Calgary, Alberta T2P 3H2 (403) 292-4800.

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Chapter 1

Introduction

Since the publication of the September 1988 Report[1], four key developments on world and North American energy markets of particular interest to Canada are:

- the narrow variation of world oil prices, in the range of $16-$20 (in $US of 1990) for West Texas Intermediate (WTI) till the Mid-East crisis of August 1990, followed by the Iraqi occupation of Kuwait and associated oil price volatility; this contrasts with the experience of the previous years, with sharp downwards price breaks in 1982 and 1985-86;
- the growth in North American natural gas trade;
- some concern about the long-term adequacy and sources of electricity supply in the U.S.; and
- the increasing public concern about protection of the environment from some of the effects of energy use.

During the extended period of relatively strong economic growth in OECD countries from 1983 to 1990, OECD and world oil demand has increased much more modestly such that, by 1989, oil consumption was just slightly above the 1979 level. Incremental demand has been met largely from increased production by OPEC countries. At the same time, world oil reserves grew more than they had since the 1950s.

With moderate demand growth and a comfortable supply situation, there was no sustained increase in **world oil prices** between 1987 and mid-1990. WTI spot prices fluctuated mainly in the range of $16-20/bbl. This performance of the world oil market has exacerbated tensions between certain OPEC countries with conflicting objectives: some preferring a long-term strategy of preserving the world market for oil with stable and competitive prices, others desiring immediate price increases to meet their present revenue requirements.

In the aftermath of the Gulf war there is uncertainty about whether and how Middle Eastern oil producing countries will collaborate on oil supply and price in the future. It is significant, both in terms of functioning of the market and in terms of assessing Middle East producers' policies, that the crisis situation leading up to the Gulf war saw only a relatively short-lived spike in world oil prices, in real terms at a level well below that reached in 1981 during the Iraq-Iran war, and that when war started prices fell sharply. Nonetheless we do not expect smooth linear behavior of oil prices in the future. They are likely to fluctuate, at times considerably. However we believe that a number of factors will tend to limit the range over which oil prices are likely to be sustained over the next twenty years. This sustainable range depends upon various plausible world supply and demand conditions, including the influence of any OPEC strategy. We discuss these conditions in Chapter 2.

The most noteworthy features of the North American **natural gas** market over the past several years have been

- the growth in Canadian gas exports to the U.S. (from 781 PJ in 1986 to 1510 PJ in 1990);
- rather flat natural gas prices; and
- the intense activity to expand pipeline capacity especially into the U.S. Northeast and California markets, in light of actual and expected natural gas demand growth in these markets.

There is a large supply overhang in North America at the present time, but an expectation that the market will become more balanced within the next several years. Looking at the longer term, there remains uncertainty about the ultimate size of the natural gas resource base in conventional areas of Canada and the U.S., as to whether it is 800 EJ to 1200 EJ or even more. However, from a preoccupation about possible inadequacy of supply less than a decade ago, the main uncertainties now relate, on the one hand, to

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1 *Canadian Energy Supply and Demand 1987-2005*, Summary and detailed reports, National Energy Board, September, 1988.

competitiveness of alternative supply sources and size of the gas market and, on the other hand, to future finding costs and the timing and extent of price change needed to replenish productive capacity as required. To a large extent, interest is now focussed on questions of market size, the role of gas in displacing other fossil fuels, price developments, gas flow patterns and pipeline projects. This subject area forms a major part of our analyses in this report.

Over the past several years, growth of demand for **electricity** has often exceeded utilities' expectations. The reasons for it are not yet well understood. At the same time, there has been growing public concern about the high costs and environmental implications of augmenting electricity generation and transmission capacity. There is no supply technology which does not have environmental impacts. One response to this demand and supply dilemma is to mitigate demand growth by encouraging conservation and efficiency improvements. There is no question about the existence of considerable potential for such improvements; the uncertainties relate mainly to the extent of this potential and to the cost of such measures relative to the cost of new generating capacity.

In this report, we have included in our control case electricity demand projections those conservation and efficiency programs which have been announced. We indicate other measures for efficiency improvement in Chapter 11 (Energy and the Environment), where we also discuss environmental factors associated with alternative electricity supply options.

When we published the 1988 Report, we mentioned the "increasing concern in Canada and abroad that present patterns of energy use may not be compatible with tolerable **environmental quality**", and we said that the premise of our energy business being conducted in the future much as it has been in the past is increasingly open to question.

Since then, public concern about global warming, acid rain and low-level ozone has increased, and the production, transportation and use of fossil fuels is a perceived contributor to these problems. Numerous studies, conferences and legislative initiatives have been undertaken on the relationship between fossil fuel use and the environment.

This is clearly a global issue, the importance and dimensions of which are subject to much debate. Fossil fuel use is not the only or - in some cases - the largest source of greenhouse gas emissions, and Canada's share of world emissions is small. Nonetheless, in today's world no one can ignore concerns about the potential impact of energy use on the environment. Therefore in this report we provide information about emissions of interest to those analyzing the environmental implications of domestic energy supply and demand.

The Board has always recognized that there are considerable **uncertainties** about the future evolution of energy markets, on account of both demand and supply behaviour. Informed comment from our consultations as well as accumulated experience indicates the importance of giving greater prominence to the key uncertainties influencing energy markets. To do so, we are expanding the analysis of the impact on energy supply and demand of alternative projections of certain key variables.

In our 1986[1] and 1988 reports we have stressed the uncertainties related to economic performance and world oil prices by analyzing different scenarios having lower and higher world oil prices and economic growth rates.

In deciding upon the areas of greatest analytical interest and a suitable corresponding framework for this report, we decided to focus on other areas of interest and considerable uncertainty which deserve increased analytical attention - these being the future performance of the North American natural gas market, and the relationship between energy production and consumption on the one hand and the environment on the other.

Because we wish to expand the analysis in these ways, while keeping the "cases" or "scenarios" to a manageable number, we provide a single Control Case of Canadian energy supply and demand based on one set of world oil prices, and national and regional economic growth projections.

We do not view this Control Case as a most likely projection. It is a centre-point around which we have conducted certain sensitivity tests for key variables having a plausible range of values. We do not attempt to assign probabilities of occurrence to any projection within the ranges of our sensitivity tests, as we consider them all plausible. Users of our results can select the area of the projection they prefer based on their views of the range of assumptions we have tested.

1 *Canadian Energy Supply and Demand 1985-2005*, Summary and Detailed Reports, National Energy Board, October, 1986.

We subject certain key results of the Control Case to sensitivity tests for different views of world oil prices and North American natural gas supply, insofar as there is debate and uncertainty about both of these factors and each could have an important influence on energy supply and demand in Canada, and on Canada's international energy trade prospects.

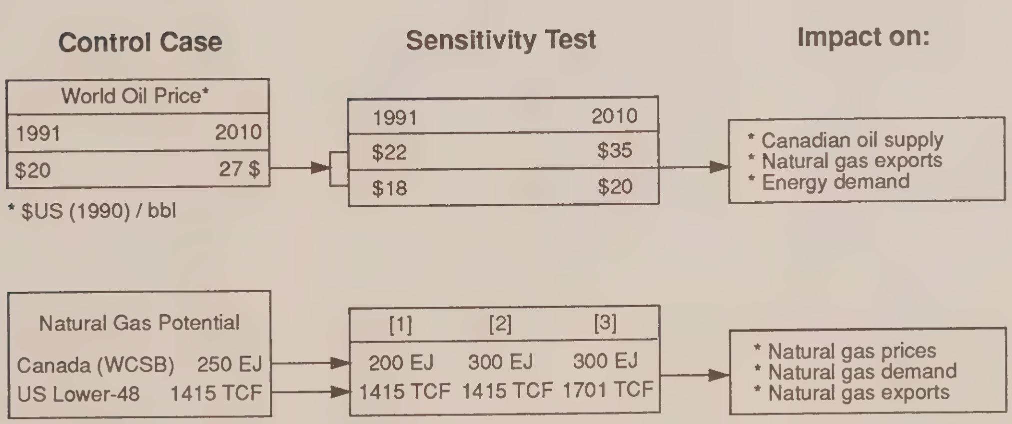
This approach to analyzing the impact of alternative oil prices is a departure from that in the 1988 Report. In that report, we situated higher and lower world oil prices in the context of higher or lower world economic growth and oil demand. Our departure from it in this report recognizes that other factors, such as producer-country supply strategy and technological change in oil production and consumption can cause oil prices to vary within a range around any given GDP projection.

Figure 1-1 shows the structure of the Control Case and sensitivity tests being presented in this report. Each test - be it for oil prices or natural gas supply - is conducted relative to the Control Case. These tests are conducted independently of each other. Each assesses the impact on the Control Case of a change in one assumption at a time (except in one gas supply test where we change two assumptions), leaving all other assumptions unchanged. We recognize that there could well be feedback effects between these factors, having secondary impacts on energy demand and supply. For example, lower oil prices or lower natural gas supply costs could stimulate economic activity, further stimulating energy demand.

We have resisted the temptation to convert these sensitivity tests into fully developed alternative scenarios for two reasons. Firstly, our main interest in the sensitivity tests is to illustrate a plausible range of results and to better understand the forces which determine the range. Since most of the impact of these particular sensitivity tests is likely to occur from the first round effects of the single assumption change, no more than that is essential to achieve the main objective. Secondly, it is necessary to contain the analysis within manageable limits, and therefore to make choices between the number or type of tests we do and their complexity, based on what is most interesting and important to observe.

These tests and the Control Case should assist readers in drawing their own conclusions about the structure and functioning of Canadian energy markets, based on their views of the various assumptions whose consequences we have examined.

Figure 1-1
Scope of Analysis



1.1 Chapter Outline

Chapter 2 describes our **oil price and economic growth projections** underlying the energy demand and supply projections for each of the Control Case and the oil price sensitivity tests.

Chapter 3 sets out the price projections for **natural gas and electricity prices**.

Total **end use energy demand** is examined in Chapter 4 by consuming sector, by fuel and by geographic region. Demand for hydrocarbons for non-energy use (mainly petrochemical feedstock) is also discussed. Fuels are needed to provide end use energy, for example, electricity generated in thermal power plants requires coal, oil, natural gas or uranium for its production. When these intermediate requirements are added to end use demand and other adjustments are made to account for conversion losses, the result is *primary energy demand,* also examined in Chapter 4.

Chapter 5 contains a discussion of ***electricity*** generating capacity and electrical energy production by province required to satisfy projected demand, including that arising within the province, firm exports, and firm interprovincial trade. Additional (i.e. non-firm) extraprovincial trade is then discussed, followed by our projection of primary energy resources required to generate electricity for domestic and export markets.

Chapter 6 discusses first our approach to ***natural gas*** price formation and flows. Next, our main input assumptions are set out. These relate to natural gas resources and supply costs in each of Canada and the U.S., the pipeline network and tolls, distribution margins, and U.S. and Canadian natural gas demand. We then discuss the results for the Control Case, including fieldgate prices, U.S. supply and demand, Canadian exports and imports, domestic demand and the various components of domestic natural gas supply. Finally, we outline the results of sensitivity tests conducted for oil prices, Canadian gas resources, North American gas resources, and backstop costs.

Crude oil and equivalent supply are discussed in Chapter 7. The chapter begins with a review of the conventional crude oil and bitumen resources underlying our projections. We then discuss reserves additions, including the methodology used to project supply costs and project timing. Next, we present our supply estimates, followed by our projections of refinery feedstock requirements and crude oil supply and demand profiles, and the implications of our outlook for major crude oil pipeline systems.

Chapter 8 begins with an overview of the domestic ***natural gas liquids*** production and transportation infrastructure. It then reviews the domestic demand for natural gas liquids; examines the prospects for supply of natural gas liquids from natural gas plants and crude oil refineries; and discusses the prospects for exports and supply/demand balances for each of ethane, propane, and butanes.

Chapter 9 begins with a review of ***coal*** resources and reserves. After discussing coal prices, transportation costs and domestic demand, it examines exports, imports and domestic production.

Chapter 10 draws together the sources and uses of energy, incorporating the projections of demand for Canadian energy in domestic and export markets and of primary energy production and imports of the preceding chapters. The chapter assesses ***primary energy supply and demand,*** and ***net exports or imports***, and also provides an international perspective, comparing Canada's energy use and production to those of other countries.

Chapter 11 assesses **emissions** of carbon dioxide, nitrogen oxides, volatile organic compounds, methane and sulphur dioxide related to energy supply and demand. It begins with a brief description of the associated environmental issues and puts the energy sector contribution into perspective by comparing estimates of energy-related emissions to emissions from other sources. The chapter then sets out the implications of the Control Case for emissions. Finally it discusses emissions reduction measures related to energy demand, electricity supply, and production and transportation of natural gas, crude oil, natural gas liquids, and coal.

Chapter 12 sets out our **major observations and conclusions** arising from the analysis presented in the report.

Appendix 1 provides **abbreviations** of names, terms and units; **conversion factors**; and a **glossary**. Appendices 2 to 11 provide supporting data for Chapters 2 to 11 respectively.

Chapter 2

Outlook for Oil Prices and Canadian Economic Performance

2.1 World Oil Prices

Despite the extended period of relatively strong economic growth in OECD countries - about 3.7 percent per year since 1983 - OECD and world demand for oil has increased by more modest rates of 1.6 percent and 1.8 percent per year respectively between 1983 and 1989[1]. In 1983, at 58 MMbd world oil consumption was at its lowest level since 1979, when it peaked at 64.5 MMbd. By 1989 it was 64.7 MMbd, just slightly above the 1979 level.

Meanwhile, on the supply side, OPEC's share of world production increased moderately from about 33 percent in 1983 to 37 percent in 1989, still far below the 48 percent share which OPEC countries held in 1979. Since the mid-1980s the growth in world demand has been met largely by increased OPEC supply. Between 1985 and 1989, non-OPEC production fluctuated within a very narrow range around 40 MMbd, while OPEC production grew from about 18 MMbd to 23.5 MMbd.

At the end of 1989, world oil reserves stood at over 1 trillion barrels, and the world reserves to production ratio (R/P) was about 44:1. These are historically high levels. The Middle East held about 65 percent of world reserves, followed by Latin America (mainly Mexico and Venezuela) with 13 percent, and the rest of the world[2] 22 percent with no one region in this group exceeding 6 percent.

Within the Middle East, Saudi Arabia alone accounts for about 25 percent of the world total. And in that area five countries - Abu Dhabi, Iran, Iraq, Kuwait and Saudi Arabia - hold almost all of the region's reserves.

The Middle East R/P was over 100, that of Latin America about 51, while the other regions had ratios ranging between 13 and 28. The five Middle East countries noted above, while comprising 63 percent of the world's reserves at year-end 1989, accounted for only 22 percent of world production. The USSR and North America accounted for about 20 percent and 17 percent of world production respectively.

In sum, there is an abundant global conventional crude oil supply, much of it at low cost, but reserves are concentrated in the Middle East among very few countries. Their production is small relative to their reserves, and they have the capability to find and produce more oil at relatively low cost.

Under these circumstances, we expect that world oil prices will be determined in the future, as they have been in the past, by a combination of market forces and political circumstances, particularly in the Middle East.

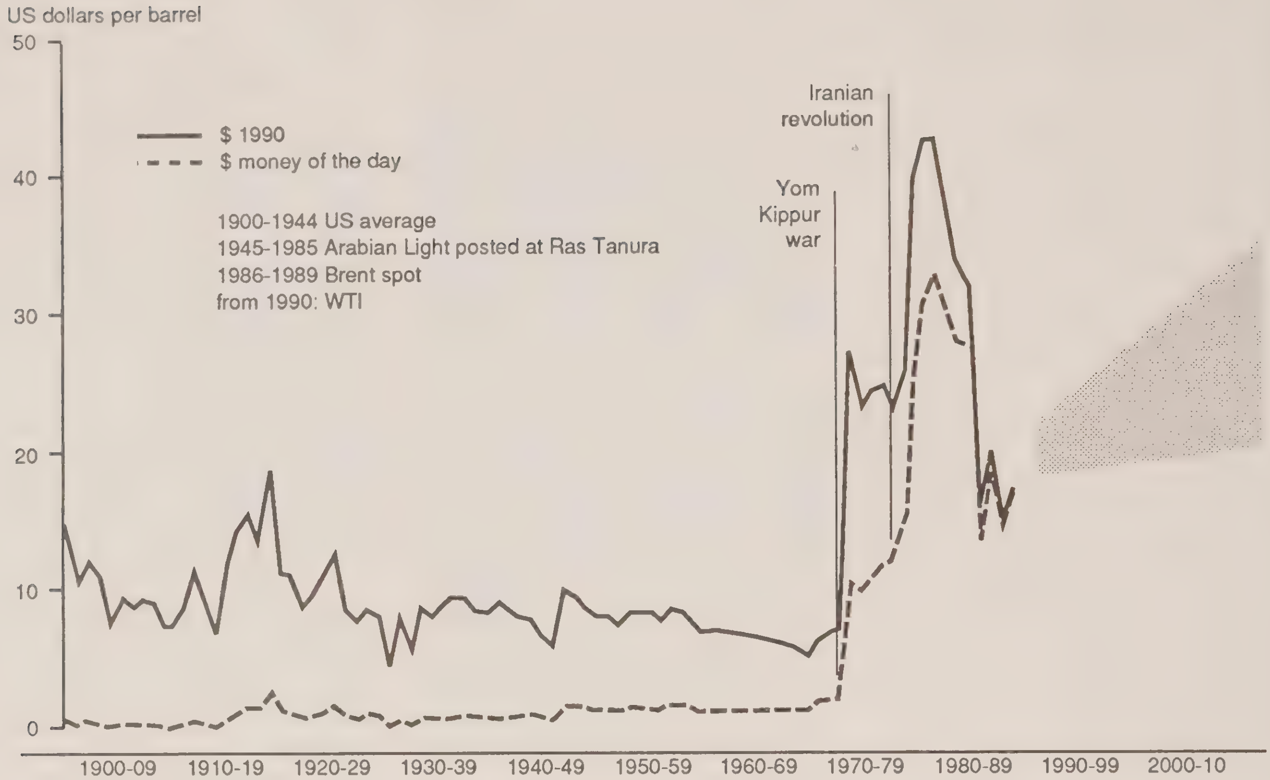
From 1900 to 1973, the real price of oil (in $US of 1990) fluctuated between about $5 and $20 per barrel, only infrequently exceeding the range of $7-$12/bbl (Figure 2-1). It spiked to $20 in 1920 due to a fear of shortage in the U.S. at that time. Since 1973, the major changes in world oil prices have been directly related to political circumstances in the Middle East. In 1974, shortly after the war of October 1973 and the oil embargo, the price jumped to about $31 (in $US of 1990), and in 1980 it spiked again to about $48/bbl shortly after the Iranian revolution. In the 1974 and 1980 episodes, spot prices escalated and OPEC official prices followed suit, suggesting that consumer anxiety drove the price up, and OPEC subsequently "solidified" the gains - but not for long.

The response to oil price increases since the early 1970s has been considerable growth and diversification of world oil reserves and very little long-term growth of world demand. World demand actually declined substantially between 1979 and 1983 under the combined weight of recession and high oil prices, then rose under the combined stimulus of economic recovery and falling oil prices. Market forces prevented oil prices from being sustained at the high levels of the early 1980s. Non-market forces prevented prices from collapsing below about $ 13/bbl. Between 1986 and early

1 1990 data was not available at time of writing. The source of data in this introduction is the BP Statistical Review of World Energy, June 1990.

2 North America, Africa, USSR, Europe, Asia and Australia.

Figure 2-1
World Oil Prices



Source for historical data: BP. Statistical Review of World Energy

1990 prices fluctuated in the range of $16/bbl to $20/bbl.

In the first half of 1990 prices were hovering around $20/bbl. In these circumstances, when Iraq invaded Kuwait in August of 1990 and United Nations' sanctions took effect, the WTI spot price reached about $35/bbl by October 1990, falling back to $27 in December. It then fell to $20 after January 15 1991, when much uncertainty in the market-place was resolved with the Coalition's military response to the Iraqi occupation of Kuwait, and with increasing evidence that other producers were compensating for the loss of Iraq and Kuwait supply.

The $35/bbl peak price of October 1990 is about 73 percent of the price level reached in 1980 (measured by US dollars of 1990), yet in 1990 considerably more Middle East oil was removed from the world market than had happened in the previous crises. As in previous crises, world demand and supply conditions alone did not warrant the extent of price escalation which occurred: production increases in Saudi Arabia, Iran, the United Arab Emirates, and Venezuela together with stock draw-downs compensated for the cut-off in Iraq and Kuwait supply.

The overall impression we draw from recent experience is that since much of the world oil resource is concentrated in a politically volatile region of the world, we should expect political events to continue to influence short-term oil prices. At the time of writing, the consequences of the Persion Gulf War are not yet apparent. We have not taken this conflict into account in our oil price projections because it would be a very speculative undertaking, and it may not be important in the context of a 20-year outlook wherein world market forces of supply and demand will most likely exert considerable influence over the economic behaviour of Middle East OPEC countries.

This historical overview of price formation leads us to several key observations:

- political events influence oil prices primarily through consumer fear of shortages;

- notwithstanding this instability, oil prices have not exceeded $20/bbl (in $US of 1990) since 1900, except over 1974-1985 and for the second half of 1990;

- market forces of supply and demand limit the scope of cartel-type control over supply and world prices, but such control limits the extent of sustained downward pressure on prices.

These circumstances make it reasonable to presume that future oil prices will continue to fluctuate in response to political events and demand and supply conditions on the world market, all of which are subject to considerable uncertainty. Therefore it only makes sense to conduct analysis on the basis of a range within which oil prices may be sustained over the study period.

A Range of Sustainable Oil Prices

We developed a range of sustainable prices using judgement based on past price behaviour, available studies, and consultations with knowledgeable analysts and participants in energy markets.

The upper and lower bounds of a range can be established by assessing the assumptions underlying a proposed range, and the likelihood of prices being *sustained* at even higher or lower levels over the period.

We selected our range based on reasoning from analyses such as those in the *Chevron World Oil Outlook* 1990, the *CERI World Oil Market* study of March 1990, proprietary services such as Petroleum Economics Ltd., London, and the results of Energy Modeling Forum[1] Study #11 (EMF 11) on world oil markets, published in spring of 1991.

EMF 11 gives particular insight to the kinds of conditions needed to sustain a very broad range of oil prices, and the analytical work done in this study was most helpful to us in selecting our oil price range.

An objective of the EMF study was to find a price path which balances world supply and demand for oil. The three cases in which this was attempted were:

(1) OPEC countries compete rather than act as a cartel, and world GNP grows at 2.9 percent per year;

(2) OPEC countries operate as a cartel and world GNP grows at 2.9 percent per year; and

(3) OPEC countries operate as a cartel and world GNP grows at 3.9 percent per year.

The range of results for each of these cases is outlined below.

In case 1 (no OPEC cohesion, and 2.9 percent per year world GNP growth) the range of results was approximately[2] as shown in Figure 2-2.

The $10 projection is a view that with no OPEC cohesion and bountiful low-cost supply capability, producer competition to supply the market will prevent oil prices from exceeding $10/bbl. This perspective cannot be dismissed out of hand, because depending upon demand there is up to fifty years of world oil *reserves* whose cost of production is below $10/bbl. Therefore in a strongly competitive market, prices could rest even below $10/bbl insofar as the cost of production establishes a floor price for crude oil. However a number of factors would prevent the price of oil from remaining at such low levels over the period through 2010. For example, the full-cycle replacement costs of non-OPEC oil generally exceed $10/bbl by a considerable margin. This therefore establishes an "alternative value" for Middle Eastern supply. EMF 11 partcipants concluded that in the knowledge of this, OPEC countries can gain by achieving at least enough cohesion on supply management to defend a price competitive with non-OPEC supply.[3] It was the view of most EMF participants that to sustain such low oil prices, demand growth would have to be very low and OPEC willing to supply an increasing market share at these prices. Participants questioned the likelihood of this scenario. These considerations would push the price above the low boundary in the range of Figure 2-2.

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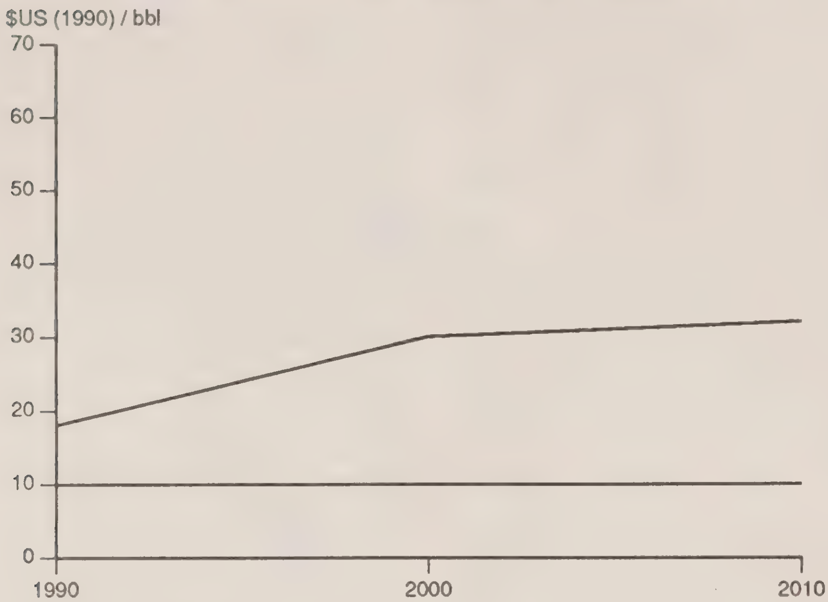
1 The Energy Modeling Forum is an organization located in Stanford University, Palo Alto California, which has a membership of energy system modellers, energy supply companies, consulting firms and government departments. The Forum undertakes and publishes studies on topics of particular current interest, combining both quantitative and qualitative analyses done by its members according to an agreed work program for each study.

2 One outlier in 1990 at $7/bbl and another in 2010 at $48/bbl are not shown.

3 It is also possible that the optimal OPEC strategy could be to set prices on the basis of those of other energy forms.

Figure 2-2

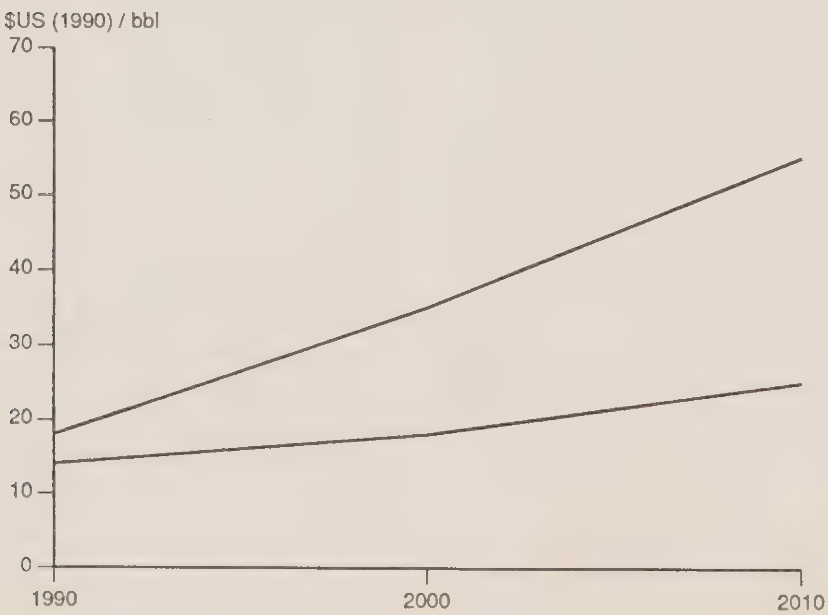
Range of World Oil Prices with Competitive OPEC and World GNP Growth 2.9% / yr.



Source: Compiled from EMF-11 results

Figure 2-3

Range of World Oil Prices with OPEC Cartel and World GNP Growth 2.9% / yr.



Source: Compiled from EMF-11 results

The high end of the range reflects oil demand increasing at about the same rate as GNP growth, holding prices constant. A more plausible view is that efficiency improvements and off-oil substitution would result in world oil demand growth below world GNP growth. The latter view produces price paths below the high boundary of the range in Figure 2-2.

The high end of the range also occurred because several modellers maintained constraints on OPEC capacity expansion; hence, increased capacity utilization triggered rather large price increases. In the other results, OPEC capacity was allowed to expand, keeping prices generally below the $20 range.

In Case 2 (OPEC operating as a cartel, and 2.9 percent per year world GNP growth) the range of results was approximately[1] as shown in Figure 2-3. Generally speaking, the major factors driving the large wedge between the lower and the higher end of the range in Figure 2-3 are different views of world oil demand growth and OPEC supply and pricing strategy within the cartel concept.

The higher end of the range reflects a combination of high demand growth and restrictive OPEC production strategy, while at the lower end of the range, demand growth is lower and OPEC as a group sees itself in long-term competition with non-OPEC oil or other fuels; therefore it increases output to meet demand at lower prices, in order to preserve a long-term stable market for OPEC oil.

To illustrate the kinds of demand and supply conditions causing

1 An outlier at about $37/bbl in 1995 is not shown.

such a large eventual price range in this case, by year 2010 at the lower end of the range world demand is about 60 MMbd and OPEC supply is about 43 MMbd. At the upper end of the range world demand is about 78 MMbd and OPEC supply 33 MMbd.

In our judgement, much of the upper portion of this range depends upon an unlikely combination of rather high demand growth considering the rapid rate of price escalation, and quite restrictive OPEC output considering the recent market strategy of major Gulf producers such as Saudi Arabia, Kuwait, and the Emirates, which have expanded output to meet growing demand at prices in the range of $20 or below.

The OPEC production and pricing strategy in the lower portion of the range recognizes that supply constraints and price escalation results in demand reduction and the development of competitive non-OPEC supply, which, once developed, is available for many years at low operating costs. Hence OPEC expands supply considerably to maintain a large market share. There may be grounds for discomfort with the view that OPEC would not escalate prices once it commands a large share of the market. However, one model in EMF 11, that of Decision Focus Inc.(DFI), calculated an OPEC long-term output policy based on a rule of present value revenue maximization yielded high OPEC output and prices in the lower end of the Figure 2-3 range. This result occurs because DFI adopted a modest oil demand growth projection (consistant with a recent U.S. Energy Information Administration outlook) and they suggest a quite elastic non-OPEC supply response as oil prices increase.

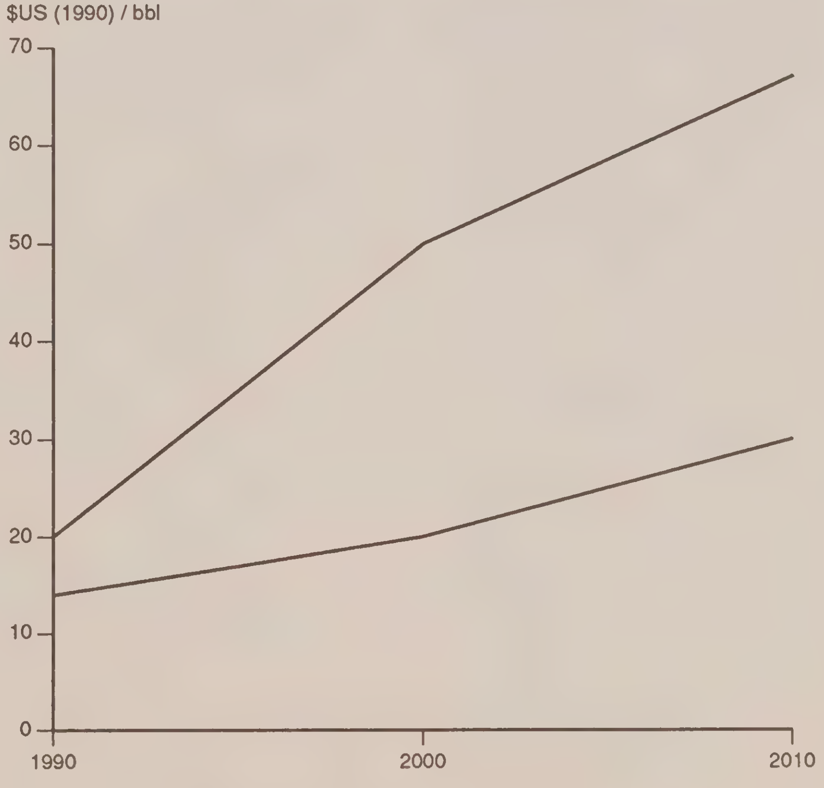
In Case 3, (OPEC operating as a cartel and 3.9 percent per year world GNP growth) the range of results was approximately as shown in Figure 2-4. It is similar in rationale and results to the picture in Figure 2-3, but several dollars per barrel higher, in light of the stronger GNP and oil demand growth. To place much weight on the upper portion of this range one would have to believe that in a context of the world economy growing at almost 4 percent per year over the next twenty years, there will be little autonomous energy efficiency improvement in the use of oil, such that, notwithstanding very high oil prices, world demand will increase by almost 20 MMb/d by 2010 and that OPEC supply will be constrained in the 30-35 MMb/d range. We think that this combination of circumstances may have a low probability of occurrence, therefore we have chosen not to use a price range broad enough to accommodate these assumptions.

The main considerations underlying our estimate of a sustainable range are that:

- between 1989 and mid-1991 oil prices have been about $US 20/bbl, followed by the price shock of August to December 1990 related to the Persian Gulf crisis, whereafter prices fell back to $20/bbl or below;

Figure 2-4

Range of World Oil Prices with OPEC Cartel and World GNP Growth 3.9% / yr.



Source: Compiled from EMF-11 results

- world oil consumption is likely to grow slowly, in a context of world economic growth in the range of 2.5 - 3.0 percent per year;

- the incremental cost of non-Middle Eastern supply is expected to increase with cumulative production, although technological progress in oil exploration and development is likely to mitigate the impact of resource depletion on costs; and

- provided that world oil demand grows modestly, low-cost world supply will likely be sufficient to sustain oil prices within a fairly narrow range over the outlook period.

Our oil price range is that shown in Figure 2-5. The range (in $US of 1990) is between $18 and $22/bbl in 1991, growing to between $20 and $35/bbl in 2010.

We do not wish to convey a rigid picture about the size or character of this range. The range could be broader, but the broader it gets the less the likelihood of prices being *sustainable* around its upper or lower edges. Nor should we consider these edges to be very sharp. They are meant to be indicative rather than precise trigger points of further market adjustment.

Figure 2-6 shows the position of the NEB range within the outer envelope of all the EMF results. Several of the EMF modellers obtained results which resemble the range we have selected - in particular the results obtained in the EMF study by Decision Focus Inc., and the Canadian Energy Research Institute.

Figure 2-7 shows the NEB range relative to several other projections

Figure 2-5
NEB World Oil Price Projections

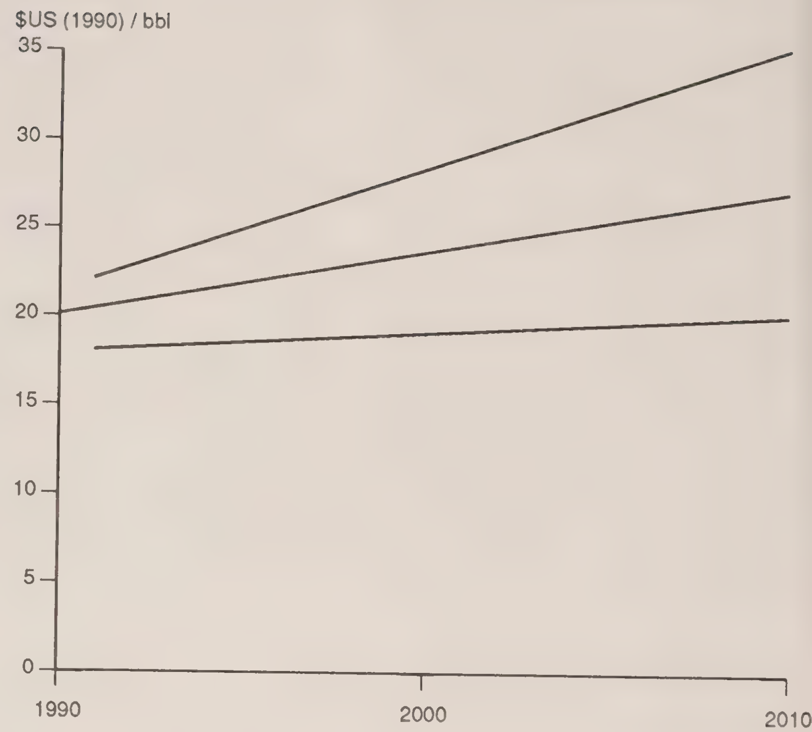
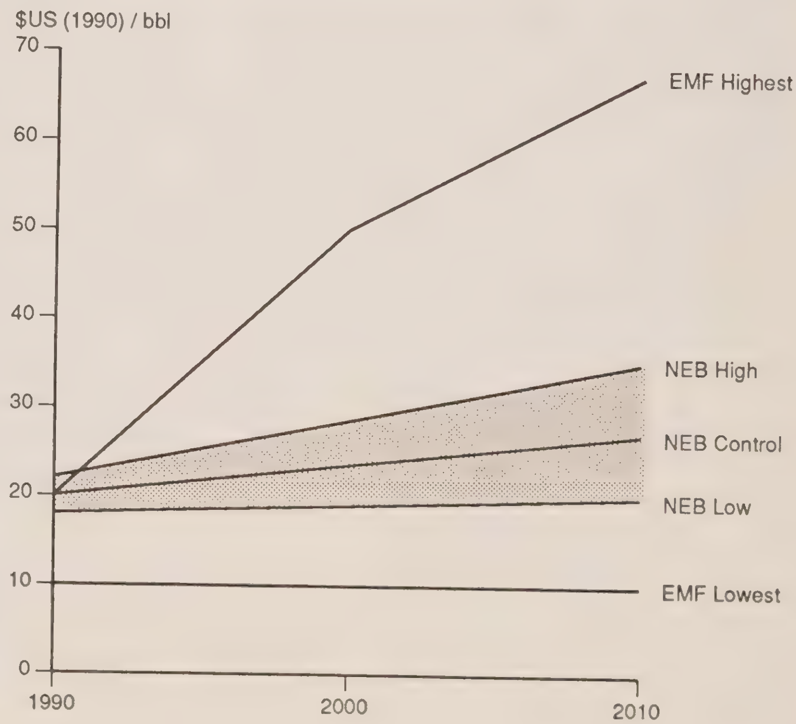


Figure 2-6
NEB/EMF World Oil Price Ranges Compared



in the public domain: the U.S. Energy Information Administration[1] the Gas Research Institute[2] Chevron Incorporated[3], and the Canadian Energy Research Institute[4].

At any time, oil prices could move outside of the bounds of this range for any number of reasons. Once that happens however, we expect there to be market reactions which would have the effect of moving the price back into the range.

If the price exceeded the upper end of the range for some time, prices would be high enough to reduce the growth rate of demand and to induce additional non-OPEC supply. (For example, within Canada, higher cost supply sources such as oil sands mining projects and enhanced oil recovery would be more attractive investment opportunities.) Once this supply is on-stream, it can be produced as long as prices are sufficient to recover (lower) recurrent costs, allowing prices to fall back into the range as a result of slackening demand and the increased supply.

If the oil price fell below the lower end of the range and remained there for some time, the major producing countries would suffer large revenue losses in real terms relative to their current requirements, and given appropriate political circumstances, they would likely co-operate enough to constrain production and maintain prices *at least* within the lower end of the range. This is a reasonable expectation considering that:

- an $18/bbl oil price in U.S. dollars of 1990 is equivalent to about $7/bbl in U.S. dollars of 1974,

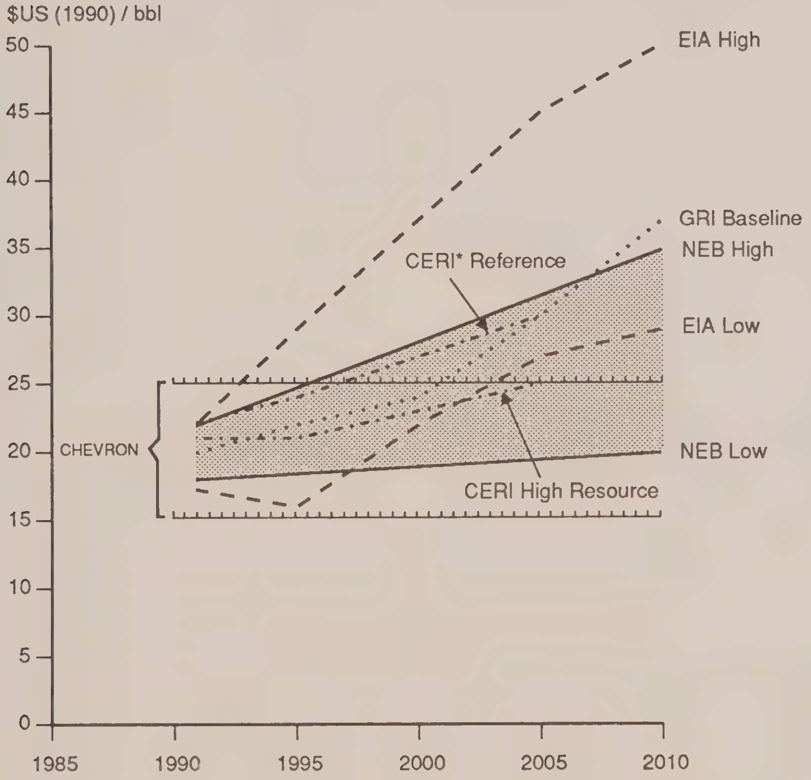
- OPEC countries have geared their economies to considerably higher real prices than this since 1974, and

- for large quantities from new fields non-OPEC full-cycle replacement costs likely exceed $18/bbl in U.S. dollars of 1990.

We believe that if prices moved outside of this band for any length of time, corrective reactions would bring them back within. The experience of 1974 to 1979 indicates that demand will decrease and non-OPEC supply will increase once prices move beyond the high $20s range, and the experience of the early 1970s and 1986 indicates that prices below $18 invite enough OPEC cohesion to protect a minimum acceptable return to the producer group: OPEC would lose revenue rather than gain market-share as prices fell much below $18. The band is narrower in the short term than in the long term, reflecting the currently comfortable supply outlook, low demand growth, near-term difficulties in co-ordinating cartel behaviour. It widens over time, reflecting the greater scope for longer-term sustainable price

Figure 2-7

Comparison of Recent Oil Price Projections



* Not shown: CERI cases where price in 2005 reaches $35 / bbl or $ 21 / bbl in their "OPEC Price Gain" and "Environmental" cases respectively.

1 U.S. Energy Information Administration Annual Energy Review 1990,
2 GRI Baseline Projection 1991,
3 Chevron World Energy Outlook 1990,
4 CERI World Oil Market Projections 1990-2005, March 1990.

Table 2-1
Control Case Oil Price Projection

	1989	1990	1991	1995	2000	2005	2010	Percent change per year (2010:1989)
Assumptions								
World Oil Price (1990$)	**20.5**	**24.5**	**20.3**	**21.6**	**23.2**	**25.0**	**27.0**	**1.3**
% change / year		19.1	-17.0	1.5	1.5	1.5	1.5	
GDP Growth Rates								
OECD Index (1989=1)	**1.00**	**1.03**		**1.15**	**1.29**	**1.44**	**1.61**	**2.3**
% change / year				2.3	2.3	2.2	2.2	
LDCs Index (1989=1)	**1.00**	**1.04**		**1.23**	**1.46**	**1.73**	**2.06**	**3.5**
% change / year				3.5	3.5	3.5	3.5	
CONSUMPTION (MMbd)								
Total OECD	**37.5**	**37.7**		**40.1**	**41.9**	**43.2**	**44.4**	**0.8**
% change / year		0.5		1.2	0.9	0.6	0.5	
Total LDC	**14.5**	**15.3**		**16.9**	**18.8**	**20.9**	**23.2**	**2.3**
% change / year		5.5		2.1	2.1	2.1	2.1	
TOTAL CONSUMPTION	**52.0**	**53.0**		**57.0**	**60.7**	**64.0**	**67.5**	**1.3**
% change / year		1.9		1.5	1.3	1.1	1.1	
SUPPLY (MMbd)								
Non - OPEC								
Total OECD	**15.9**	**15.8**		**15.8**	**14.7**	**13.8**	**12.8**	
Total Developing	**9.6**	**9.9**		**9.9**	**9.9**	**10.3**	**10.6**	
CPE Net Exports	2.1	1.7		1.9	1.5	0.8	0.0	
Processing Gains	1.1	1.3		1.1	1.2	1.3	1.4	
Total Non-OPEC	**28.7**	**28.7**		**28.7**	**27.3**	**26.1**	**24.8**	
OPEC Crude Oil	**21.7**	**23.0**		**26.0**	**30.7**	**34.9**	**39.3**	
OPEC NGLs	1.9	1.9		2.3	2.7	3.1	3.4	
Total OPEC	**23.6**	**24.9**		**28.3**	**33.4**	**38.0**	**42.7**	
TOTAL SUPPLY	**52.3**	**53.6**		**57.0**	**60.7**	**64.0**	**67.5**	

increases as cumulative consumption grows and non-OPEC supply becomes costlier.

We have selected a Control Case projection roughly through the middle of our range. Prices increase from about $20/bbl in 1991 to $27/bbl in 2010 (Figure 2-5).

Table 2-1 shows a world demand and supply profile consistent with our Control Case price projection. Other profiles would not necessarily be inconsistent with this projection, insofar as we do not envisage a rigid relationship between specific features of the supply/demand balance and the oil price.

The selection of a specific Control Case price path is necessary for calculating supply and demand projections. Because we believe that price development around the control case projection is just as likely as price movement along it, in the following chapters we also provide a range of supply and demand outcomes corresponding with our sustainable range of oil price behaviour.

While we expect that over the long term the main factors influencing oil prices are demand growth, the cost of non-OPEC supply and political developments in the Middle East, we emphasize that none of these can be predicted with enough confidence to designate a most likely projection within the range. We believe, however, that our range reflects the more likely sustainable outcomes to 2010, based on a review of historical and contemporary factors influencing oil markets, and the advice we have gleaned from recent studies and consultations.

2.2 Canadian Macroeconomic Performance

The rate and character of Canadian economic growth are important determinants of the amounts and types of energy which Canada will require over our study period. Since energy is used in the production of goods and services, it follows that, other things being equal, the higher the rate of economic growth, the higher will be the demand for energy in Canada. However, the structure of economic activity also has an important influence on the level and fuel mix of Canadian energy demand. For example, some industries use energy in their production processes much more intensively than others; and within a particular industry the kind of energy used varies according to the particular technologies being applied. Fossil fuels are also an input in the production of goods such as plastics and synthetics, and industrial and agricultural chemicals. Thus an assessment of energy demand in Canada depends not only on the overall level of economic activity, but also on the composition and technical character of this activity.

In this section we examine Canada's macroeconomic outlook over the projection period, both in aggregate and on a sectoral basis. These projections have a significant influence on the energy demand projections discussed in Chapter 4 of this report.

In the long run Canada's aggregate economic performance will be determined by the rates of labour force and productivity growth. These factors determine the rate of potential growth in the economy.[1]

The rate of labour force growth is known with reasonable certainty. The working-age population times the participation rate determines the size of the labour force. It is generally accepted that Canadian population growth will slow as fertility rates decline. However, for the next twenty years the population which will form the basis of the labour force is already largely determined. Net immigration assumptions may have a modest impact on the aggregate working-age population. For our projections we have assumed that gross immigration increases from 160 000 persons in 1990 to 256 000 persons by the year 2010.[2] (Net immigration grows from 120 000 persons in 1990 to 165 000 persons by 2010.) The increase in female participation rates has slowed in recent years and while we expect some continued gains in the future, we do not anticipate growth rates as high as those of the 1970s. Taking account of the trends in female participation and of the effect of the age distribution of the working-age population, we expect the aggregate participation rate to stabilize at about 68 percent. With the projected decline in the work-

1 Potential growth is approximately equal to the sum of labour force and productivity growth. It represents the upper bound to growth for a given unemployment rate. However, under favourable international conditions or more permissive monetary and fiscal policy, Canadian growth could exceed potential for a period of time, if there are underutilized resources in the economy. In a similar vein, if international conditions are not favourable, Canadian growth could fall short of potential, and the country could experience a rising unemployment rate.

2 Although this projection was completed before the October 1990 announcement of new higher gross immigration quotas, inclusion of these would have only a modest effect on population and economic growth.

ing age population and stabilization of the participation rate, we project that labour force growth will decline from current rates of slightly more than one percent per year during the 1990s to an estimated 0.6 percent per year between 2000 and 2010.

Productivity growth is more difficult to project. During the 1960s, Canada's output per person grew at almost three percent per year, but this performance eroded gradually during the early 1970s and then fell to only a 0.1 percent annual increase over 1973 to 1981, recovering to an average annual increase of some 1.2 percent in the 1980s.

We project productivity to grow at an average rate of slightly less than one per cent per year during the 1990s. Strong investment spending through the 1990s leads to a more efficient capital stock and boosts productivity growth to an average annual rate of some 1.3 percent in the period 2000-2010.

For a given unemployment rate, economic growth is approximately equal to the sum of labour force growth and productivity growth. Thus, our estimates of the growth patterns of these two factors imply a long-run average rate of growth of real GDP[1] for Canada slightly less than 2.5 per cent per year.[2] Business cycles will, of course, generate rates of growth above and below this level over time. We do not attempt to portray these variations.

Economic growth in the U.S., Canada's major trading partner, follows a broadly similar long-term profile. We have not built in any major changes to the pattern of international trade. In this context, however, we do allow for a relatively mild depreciation in the exchange rate of the Canadian dollar vis-a-vis the U.S. dollar from about 85 cents (U.S.) in 1990 to a level of 80 cents (U.S.) by 1995. This depreciation results from a narrowing of Canada/U.S. interest rate differentials from their very high levels in 1990-91. The exchange rate remains constant at 80 cents (U.S.) for the rest of the projection period.

An important aspect of our macroeconomic projections - particularly in determining energy demand - is the relative growth of "goods" and "services" industries. Goods producing industries (the industrial sector) include forestry, mining, manufacturing and construction. Within the industrial sector the most energy intensive industries are mining, pulp and paper, iron and steel, smelting and refining, chemicals, cement and petroleum refining.

Service producing industries (the commercial sector) comprise four distinct categories: wholesale and retail trade; finance, insurance and real estate[3]; public and private services and public administration. For purposes of energy demand projections, agriculture, utilities and transportation, storage and communications are treated separately.[4]

For the past ten years the share of services (as defined above) in real gross domestic product has been constant, as has the share of goods producing industries. This is an important matter for our projections, because energy use per dollar of real output in the industrial sector is four to five times greater than that for the commercial sector. Within the industrial sector, however, a subset of energy intensive industries uses about ten times as much energy per dollar of real output as other industries. Hence the projected evolution of energy intensive industries is also important to our demand projections.

As part of our projection of economic activity we generated internally consistent estimates of the distribution of production across industries. The share of industrial output in total real gross domestic product increases from 33 percent in 1990 to about 36 percent in 2010. Energy intensive industries, which contributed 11 percent of total output in 1989, account for 10 percent in 2010.

Within the industrial sector, manufacturing shows the strongest growth, 3.0 percent annually over the 1989 - 2010 period. Growth of the energy intensive industries is slightly below the manufacturing aggregate and that of the goods-

1 This comparison is of GDP at market prices. However, in all other references we use GDP at factor cost, consistent with individual industry and provincial estimates.

2 This compares with projections of 2.5 percent and 2.6 percent made by Informetrica and Data Resources of Canada. Informetrica Limited, "Post I-1990 Reference Case", August 1990; Data Resources of Canada. "DRI Fall 1990/Winter 1991 Long Range Focus", October 1990.

3 We exclude royalties and imputed rents from finance, insurance and real estate. This output has no energy demand associated with it. Our definition of commercial sector GDP and of the services sector, therefore, also excludes royalties and imputed rents.

4 Energy demand for agriculture is included in the residential sector; energy demand for transportation is analyzed separately; energy use by storage and communications is included in the commercial sector (though real GDP is not) and utilities' energy consumption appears as utilities' own use. The classification of goods and services is based on the NEB's energy demand data classifications. Our discussion of historical performance of these two sectors is also based on this categorization.

producing sector as a whole (Table 2-2). The composition of export demand favours durable and, to a lesser extent, non-durable manufacturing. Among the energy intensive industries, pulp and paper is expected to face resource constraints on the availability of wood in the future, which will restrain output growth. Canada's other major resource industries face increasing competition from developing countries who are building their resource sectors and penetrating world markets.

Commercial sector output accounts for 43 percent of total output in 2010 compared to 45 percent in 1990.

Growth of individual industries within the commercial sector is generally below that of the aggregate economy in the period to 2010. This is because low population growth is expected over the period. For those services which are directly related to demographic trends, our projections allow for growth in the per capita production of those services in excess of one percent annually.

The trends in goods and service production varies somewhat from the experience of the last ten years. As mentioned earlier, over that period the services share of real GDP remained relatively constant (Table 2-3). A discussion of this past trend and an explanation as to why we project a somewhat different structure for economic activity over the projection period is provided in the inset.

The regional distribution of economic growth is heavily dependent on the distribution of national growth between goods and services. The western and eastern provincial economies are relatively more dependent on resource-

Table 2-2

Output by Sector

Average Annual Growth Rates (Percent)

	1989-95	1995-00	2000-05	2005-10	1989-10
Industrial Sector	2.5	2.5	2.7	2.9	2.6
Forestry	1.5	0.9	0.8	1.0	1.1
Mining	2.3	1.3	1.7	0.5	1.5
Manufacturing	2.8	2.7	2.9	3.5	3.0
Construction	2.0	2.8	2.7	2.8	2.5
Energy - intensive[a]	2.4	1.7	1.8	1.3	1.8
Commercial Sector	1.9	2.1	2.1	2.0	2.0
Total Gross Domestic Product	**2.2**	**2.2**	**2.3**	**2.3**	**2.2**

Notes: Real Gross Domestic Product at factor cost, (1981 Dollars).
[a] Mining, smelting and refining, iron and steel, pulp and paper, chemicals, cement and petroleum refining.

Table 2-3

Distribution of Real Gross Domestic Product

(Percent)

	1986	1989 [a]	2005	2010
Industrial Sector	32.4	33.3	35.1	36.0
Forestry	0.8	0.8	0.6	0.6
Mining	5.6	5.6	5.3	4.8
Manufacturing	18.9	19.2	21.1	22.3
Construction	7.1	7.8	8.1	8.3
Commercial Sector	45.8	45.3	43.9	43.2
Other[b]	21.8	21.3	21.0	20.8

Notes: Real Gross Domestic Product at factor cost, (1981 Dollars).
[a] Estimate.
[b] Other includes agriculture, utilities, transportation, storage and communications.

Trends in Goods and Services Production

Over the past ten years the shares of goods and services production have been relatively stable. In Canada, services[1] accounted for 45 percent of real gross domestic output in 1981 and for the same share in 1989. Below average growth in education and public administration offset above average growth in health and commercial services, as discussed below. The share of goods production was 33 percent in both 1981 and 1989.

For services, or the commercial sector, it is useful to separate the component industries into two groups. The first group, wholesale and retail trade and finance, insurance and real estate provide services is related to the production and consumption of goods and services in the economy as a whole. Wholesale and retail trade, and finance, insurance and real estate (excluding royalties and imputed rents) have grown at close to 4 percent annually over the past ten years and have correspondingly increased their share of output[1]. During the 1970s and to a much lesser extent in the 1980s there have been significant social and lifestyle changes, the introduction of new services and increased reliance on services over private consumption - for example, meals consumed outside the home. Studies of the reasons for this trend have been unable to identify specific causes and it is difficult to determine whether this trend will continue.

The second group comprises the remaining components of this sector: health and education, private business services, which include such activities as business consulting services, and public administration. Health, education and public administration account for about 60 percent of the commercial sector's output.

Requirements for health and education services depend on the growth and composition of the population. Over the past ten years the health sector's output has grown faster than that of the overall economy, and real expenditures per capita have increased at 2.5 percent per year. During the 1970s and 1980s growth in education output has been sharply curtailed as enrollments continue to decline at the elementary and secondary levels. Both of these sectors - health and education - are now facing budget restrictions as provincial governments attempt to balance their budgets.

Growth of output in these two sectors may be expected to be slower than it has been over the past ten years, even though it continues to increase in real terms per capita.

Growth of public administration output was below average during the 1980s (at about 1.5 percent per year), and is now constrained by concerns over government fiscal balances. We do not anticipate any change in this position.

While we can examine trends within the industrial and commercial sectors and identify factors which have contributed to their relative growth over the last ten years, it is not possible to determine conclusively how these shares will evolve in the future. In developing our macroeconomic projections we have examined specific requirements for outputs of public services such as health and education, and we have considered the role of private services - such as wholesale and retail trade, and finance, insurance and real estate in meeting the needs of a growing economy.

In our projections we have allowed for real per capita increases in expenditure for public services such as health and education of approximately one percent annually. This reflects continued demands by the public for improved services in these areas, but also a recognition of funding constraints on the part of governments. Private service growth is in line with overall economic activity on the premise that ultimately these industries provide services which are related to the production and consumption of goods, and we have no compelling evidence upon which to project that they will grow faster than the other sectors which use their output. The aggregate service sector growth rate turns out to be less than that of the industrial sector because health, education and public administration grow by less than do private services and the latter grow by slightly less than the rate of the industrial sector.

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1 As defined above.

based industries than are the central provinces in which services and secondary manufacturing are more prevalent.

Manufacturing accounts for just over 11 percent of the Atlantic region's output. The share is 12 percent in Manitoba, 6 percent in Saskatchewan, 7 percent in Alberta and about 14 percent in British Columbia. However, in Quebec and Ontario manufacturing represents over 20 and 27 percent of those provinces' output, respectively.

Our projections for the industrial sector, and in particular the demand for manufactured goods relative to other industrial production, result in relatively stronger growth of Ontario and Quebec, though growth of the Prairies and British Columbia is close to that of Quebec (Table 2-4).

In the Atlantic region, growth lags the national average. The region's manufacturing activities are concentrated in the food and beverage, and pulp and paper sectors, which are not expected to grow strongly. Moreover, resource constraints in the fisheries limit growth of the fishing and fish processing industries. The region's construction and mining sectors benefit during the construction period of the Hibernia project, although with completion of the construction, that sector's output declines.

Quebec's economy performs close to the national average. Continued hydroelectric development is a major source of investment in the province, as in the past. Quebec's manufacturing output is concentrated in nondurables production, which in our scenario does not experience as high demand growth as durable goods. Resource constraints in the forestry sector, however, are assumed to restrict prospects for forestry and pulp and paper, and output grows at or below two percent per year.

While Ontario's manufacturing sector has been affected by the current recession, once economic growth resumes, Ontario will be the major beneficiary of demand for durable goods. The motor vehicles and parts industry is projected to resume growth as foreign manufacturers move production to Canada. Primary metals - including iron and steel production - and metal fabrication also contribute to Ontario's performance as they supply Ontario's manufacturing sector with required inputs. Residential construction is likely to grow at a slower pace than it has in recent years, reflecting the slower rate of increase in household formation.

Economic activity in the Prairie region varies by province, reflecting the different sources of growth across the region. In Manitoba, the service sector accounts for approximately 51 percent of the province's activity, followed by manufacturing at 12 percent and transportation at 6 percent. In Saskatchewan, services account for 38 percent of output followed by agriculture (14 percent), resource extraction and transporta-

Table 2-4

Output by Region

Average Annual Growth Rates (Percent)

	1989-1995	1995-2000	2000-2005	2005-2010	1989-2010
Atlantic	1.8	2.1	1.8	1.3	1.8
Quebec	2.3	2.2	2.2	2.2	2.2
Ontario	2.2	2.6	2.7	2.9	2.6
Manitoba	1.5	1.9	1.5	2.1	1.8
Saskatchewan	1.6	1.2	1.1	1.8	1.4
Alberta	2.3	1.4	2.0	1.5	1.8
Prairies	2.0	1.4	1.8	1.6	1.7
British Columbia and Territories	2.0	2.1	2.3	2.1	2.1
Canada	**2.2**	**2.2**	**2.3**	**2.3**	**2.2**

Notes: Real Gross Domestic Product at factor cost, (1981 Dollars).

tion (12 and 4 percent, respectively). In Alberta, services account for 35 percent, resource extraction 23 percent, transportation 3 percent and manufacturing 7 percent.

In the Control Case, we have assumed that grain prices recover gradually to 1985 levels, but do not increase much in real terms above that. As a result, the outlook for agriculture remains relatively weak throughout the projection period. This has the greatest impact on the Saskatchewan economy.

Although we have included several specific energy projects (see Chapters 6 and 7) which are located in the Prairie region and which are assumed to be built in the 1990s, the region's economy does not show evidence of a prolonged period of extraordinary growth. Construction and mining activity - particularly in Alberta - picks up, but the production of conventional crude oil is declining and the output of new projects is not enough over the long run to offset this trend[1].

In British Columbia, services account for just under 47 percent of output, manufacturing 15 percent, transportation 7 percent, construction 9 percent, resource extraction 4 percent and forestry 18 percent. We expect that resource constraints, along with moderate demand, will limit growth in the forestry and pulp and paper sector to just under 2 percent per year. Growth of the other resource sectors, in particular mining, is also expected to be weak. Despite more robust growth of British Columbia's manufacturing sector, its share is relatively small (as compared to that of Ontario or Quebec), leaving the province's overall growth below the national average.

Our macroeconomic projection focuses on the long-term prospects for the Canadian economy which, as noted, are driven by labour force and productivity growth. But for the immigration level, labour force growth over the next two decades is known with reasonable certainty. Barring a major sustained change in the level of immigration, potential economic growth will not be substantially affected by changes in immigration levels.

With respect to productivity growth, developments are far less certain.

Major changes are occurring in world trading relationships as a result of changing economic policies (e.g. changes in the GATT and in the commercial relationships among regional blocs of countries) and far reaching changes in political and economic organization, particularly in Eastern Europe.

Within Canada some change in policies has already occurred (as in the shift from the Federal Sales Tax to the Goods and Services Tax) and others have been announced (for example, the environmental policy framework announced in the Green Plan). Such changes along with technological developments can have powerful but currently unknown effects on productivity growth and on the composition of production in the economy. The current move to large trading blocs and globalization of industry could pose a threat to our outlook for the Canadian manufacturing sector, if Canada is not able to maintain a competitive position in the world economy. Some of the implications of alternative economic assumptions for energy demand are discussed in Chapter 4.

As is the case for world oil prices, our economic growth projections are meant to portray sustainable trends. We have not attempted to estimate business cycles. We recognize that growth rates will likely fluctuate above and below our projections; our purpose, however, is to estimate the longer-run implications for energy demand of trends in the growth and structure of economic performance, not the year-to-year variations.

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1 When economic activity is expressed in constant 1981 dollars, oil has a much larger weight than natural gas. Thus in the projection, even if natural gas production is expected to dominate oil activity in the future, the 1981-based measure of activity will accord a larger weight to the declining oil production.

Chapter 3

Natural Gas and Electricity Prices

3.1 Natural Gas Prices

Between 1975 and 1986 the price of natural gas in Canada was regulated. However, since the signing of the Western Accord in March 1985, there has been a shift toward market price determination. In Chapter 6 we describe how we have determined fieldgate natural gas prices in a North American context, in which North American supply and demand conditions determine the prices of natural gas in Canada and the U.S.

To calculate average Canadian burner tip prices for the residential, commercial and industrial sectors we add transportation and sectoral distribution costs to the fieldgate price of natural gas. For example, the residential end use natural gas price in Quebec is determined by adding to the Alberta fieldgate price the cost of transporting gas to Quebec on the NOVA and TransCanada systems and the average residential distribution margin for Quebec. To calculate end use prices in British Columbia we add the costs of transportation and distribution within British Columbia to the B.C. fieldgate price. For Saskatchewan end use prices, we add the intra-Saskatchewan transportation and distribution costs to the Saskatchewan fieldgate price. (The Saskatchewan fieldgate price is roughly equivalent to the delivered price of Alberta natural gas to the Alberta/Saskatchewan border.)

In 1989, natural gas transportation and distribution costs together accounted for about 60 percent of the average residential end use price in Ontario. For commercial and industrial users in Ontario, the corresponding proportion was about 55 and 45 percent respectively. Thus, assumptions about future transportation and distribution costs are an important component of end use price formation.

In our Control Case, we have assumed that transportation and distribution costs in Canada remain constant in real terms, with the following exceptions:

- expansion of the Nova system is assumed to increase real transportation costs within Alberta by about 18 percent between 1990 and 1992 - these transportation costs then are assumed to remain constant in real terms from 1992 to 2010;
- real transportation costs on the TransCanada system from the Alberta border to Eastern Canada are assumed to increase by about 8 percent in 1991, then are held constant in real terms thereafter; and
- based on discussions with industry, average industrial distribution margins in the Gaz Métropolitain system are expected to decline from about $1.10 per gigajoule in 1990 to $0.88 (1990 dollars) by 2007, and to remain constant thereafter.

The delivered price of natural gas in Quebec and Ontario is considerably higher than the corresponding price in Alberta (Table 3-1). Thus, in 1990, the residential burner tip price of natural gas in Quebec and Ontario was $6.86 per gigajoule and $5.22 per gigajoule, respectively, compared to $3.33 per gigajoule in Alberta. The difference between end use natural gas prices in Ontario, Quebec and Alberta is largely due to differences in the cost of transporting and distributing natural gas to each of those markets.

In recent years, direct purchasers of natural gas have been able to buy at a discount as compared to purchases from distributors. In 1990, the discount at the fieldgate was about $0.30 per gigajoule for natural gas going to eastern Canadian markets. We expect this price discounting to disappear by 1997, as the current deliverability surplus is eroded. As is described in Section 4.2.1, we have maintained the same fieldgate price to all users once the discounting disappears. This treatment differs from the approach in the 1988 Report, whereby "streaming" of prices between end use sectors continued over the study period in order to maintain the competitiveness of natural gas in the switchable markets.

Table 3-1 shows that, for the Quebec industrial market, the price of natural gas exceeds the price of heavy fuel oil throughout the projection period. In Ontario, industrial

Table 3-1

Natural Gas End Use Prices

($C 1990/Gigajoule)

	1989	1990	1995	2000	2005	2010
Quebec						
Residential	7.05	6.86	7.52	8.39	9.08	9.77
Commercial	5.74	5.58	6.30	7.17	7.86	8.55
Industrial	3.48	3.57	4.82	5.68	6.40	7.30
Industrial Heavy Fuel Oil	3.25	3.50	4.46	4.88	5.20	5.56
Ontario						
Residential	5.38	5.22	5.88	6.69	7.34	7.98
Commercial	4.35	4.22	4.92	5.74	6.39	7.03
Industrial	2.79	2.88	3.82	4.69	5.43	6.27
Industrial Heavy Fuel Oil	2.74	3.50	4.15	4.56	4.86	5.20
Alberta						
Residential	3.32	3.33	3.97	4.79	5.43	6.08
Commercial	2.48	2.49	3.07	3.89	4.53	5.18
Industrial	1.57	1.61	2.45	3.32	4.04	4.84
Industrial Heavy Fuel Oil	2.74	3.48	3.96	4.35	4.66	4.99

Note: Prices are not adjusted for relative fuel efficiencies.

natural gas was more than 60 cents per gigajoule cheaper than heavy fuel oil in 1990. However, natural gas prices are projected to increase more rapidly than the price of heavy fuel oil. Consequently, by 1999, natural gas and heavy fuel oil reach price parity in Ontario's industrial market and, by 2010, the price of natural gas is over 20 percent higher than the heavy fuel oil price. In Alberta, where transportation and distribution costs are low, natural gas is expected to maintain its cost advantage over heavy fuel oil throughout the projection period.

3.2 Electricity Prices

Electricity prices to Canadian consumers are regulated by provincial boards or provincial governments with the objective of ensuring that rates are sufficient to recover the utility's capital and operating costs, while also providing a return consistent with certain stated financial objectives. Generally, during periods of little construction activity or low capacity additions, particularly for hydro and nuclear systems, price increases are lower than during periods of major investment. Utilities which export electricity have, in the past, used export revenues to temper rate increases to domestic users, through various rate stabilization mechanisms.

The prices used in our demand projections are effective prices. They differ from published utility rates insofar as effective prices include rebates, typically for large industrial users, which appear on the consumer's bill and provincial and federal taxes.

The projection of electricity prices in the Control Case reflects announced changes through 1993

where available. After that year, in most provinces, electricity prices are assumed to remain constant in real terms. This is the same approach as used in the Board's 1988 Report.

Table 3-2 shows projected average annual nominal price growth by region for the periods 1990-1993 and 1993-2010. For the near term, we have included all announced changes to rates, rebates and taxes in our price outlooks. Based on advice from utilities, the Goods and Services Tax (GST) is assumed to add a full 7 percent to consumer prices; there are no offsetting declines reflecting the removal of the federal sales tax (FST), because most of the cost of electricity arises from past investments in capital equipment for which past FST is a sunk cost. There was no FST on most fuel and other operating costs. As well, GST is included in commercial and industrial prices as the prices paid to the utilities by these sectors include all taxes.

Over the period 1990-1993, electricity prices rise at varying rates by sector and province; large annual average increases, well in excess of inflation occur in Quebec, Ontario and Alberta. To a large extent, these reflect very large increases in 1991, followed by more modest growth through 1993, the last year of announced price changes for any utility at present.

For the **residential** sector, 1991 electricity prices increase by between 7 to 23 percent in nominal terms. (See Appendix Table A4-1). Saskatchewan rates are unchanged in 1991, except for the increase of 7 percent reflecting the GST. The Atlantic provinces, Quebec, Ontario and Manitoba show price gains of 13-16 percent, while Alberta residential customers face the greatest increase, at 23 percent, as rate increases were compounded with removal of certain rebates and the introduction of the GST.

Commercial sector electricity prices in 1991 generally increase more rapidly than those for the residential sector. In Quebec, where effective prices increase by just over 30 percent, the demand charge rises by almost 50 percent, and the energy charge by about 8 percent. Although the provincial sales tax rate has declined from 9 percent to 8 percent, the introduction of GST more than offsets this. Ontario commercial sector prices rise by 28 percent due to an increase of about 13 percent in the energy charge, the removal of a 10 percent rebate (which existed up to 1991) and the inclusion of GST. Alberta commercial users face an increase of 21 percent, as demand charges rose by 13 percent and the GST was added. In the remaining provinces, commercial sector prices rise between 6 and 14 percent.

The pattern for 1991 **industrial** prices is similar to that of commercial prices. A 5 percent rise in the

Table 3-2

Average Annual Growth In Current Dollar Electricity Prices

(percent)

	1990-93			1993-2010
	Residential	**Commercial**	**Industrial**	**All Sectors**
Atlantic	7.0	6.9	7.1	4.6
Quebec	8.1	11.9	8.5	4.6
Ontario	10.2	12.9	11.8	4.9
Manitoba	6.8	5.9	6.0	3.6
Saskatchewan	5.1	4.9	4.9	4.6
Alberta	9.0	8.5	8.5	4.6
British Columbia	3.7	3.2	3.2	4.6

Ontario energy charge and the removal of rebates, large increases in Alberta's industrial demand and energy charges, and rate adjustments in other provinces lead to growth of industrial prices at rates very close to those of commercial prices in all provinces except Quebec. In Quebec, industrial prices rise by about 16 percent as a reduced consumption charge and increased rebate partially offset higher demand charges and the GST.

In 1992, electricity prices increases are generally in the 5 to 6 percent range for all sectors and provinces, except Ontario, where price growth is expected to be about 8.5 percent and British Columbia, where only a 1.5 percent nominal increase is anticipated.

Beyond 1993, based on advice from utilities, we assume that price growth is equal to the general rate of inflation in all provinces except for Ontario and Manitoba. For Ontario, the price growth follows that of Ontario Hydro's most recent long-term outlook, which indicates price growth at the rate of inflation through the year 2005, followed by real increases of one percent per year reflecting Ontario Hydro's revenue requirements and anticipated construction schedule. In Manitoba, electricity prices decline by one percent per year in *real* terms. This reflects the expected low cost expansion of the Manitoba hydro system and the benefits of extra-provincial electricity sales, which will be used to reduce prices to provincial customers.

In our discussions with major Canadian utilities regarding their long-run outlook for electricity pricing, most agreed that existing financial practices and expected capacity additions could lead to periods of declining real prices. However, the uncertainties surrounding these parameters could equally lead to prices tracking the general rate of inflation.

As in our last report we feel that there are several specific areas of uncertainty which could result in price increases greater than those we have projected:

- Changes to existing financial targets could occur as provincial governments look for additional revenue sources to reduce their debt and deficits; they may require an increased return from utilities.
- The role and size of export revenues may change as the need for additional capacity to meet domestic electricity needs reduces the future role of electricity exports in cushioning rate increases.
- Costs could be higher than initially expected because there are uncertainties over costs of future expansions, uncertainties over engineering requirements for new sites, and additional costs could be incurred to mitigate environmental problems.
- Some systems will require major upgrades to transmission and distribution to ensure system reliability.
- Additional costs could be incurred to meet electricity needs in the short run, or interest during construction could increase, if delays occur in the construction of major projects.

Chapter 4

Energy Demand

In this chapter, we first describe the basis for our projections of end use energy prices. We then examine end use energy demand by sector, and by fuel and region. End use requirements include space and water heating, motive power for equipment, appliances and vehicles and process fuel for industries. We then describe our projections of primary energy demand for Canada. To arrive at the amount of primary energy required, we add to end use demand the fuel and losses associated with the production and distribution of each energy form (natural gas, NGL, coal, electricity, oil, etc.). We also examine the major uncertainties associated with any long-run projection of this type, and their impacts on the level of energy demand.

Energy demand is a derived demand. That is, energy is needed to perform another function, such as space heating, powering motors for industrial processes or automobiles for transportation. How efficiently energy is used depends, among other things, on the characteristics of the capital equipment which consumes the energy, for example, the thermal efficiency of a house, furnace efficiency or automobile efficiency.

Since the oil price shock of the early 1970s, energy use patterns in all major industrialized countries have changed dramatically. There have been major shifts off oil and significant conservation measures to reduce oil and other energy use through improved energy efficiency. Energy demand in Canada declined in absolute terms in the early 1980s as a result of major improvements in automobile fuel efficiencies, explicit conservation measures, and the 1982 recession, in which there was a substantial decline in economic activity.

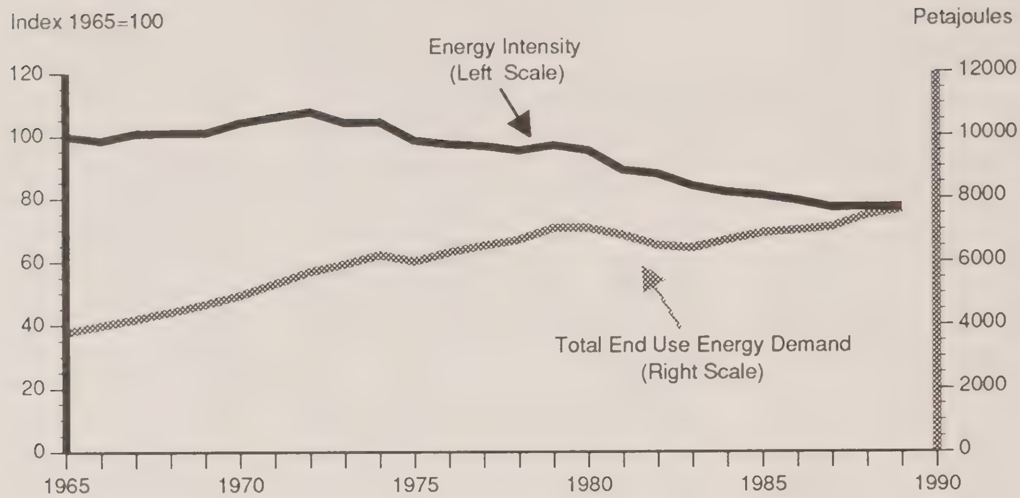
Since the mid-1980s, and particularly with the collapse of oil prices in 1986, there has been renewed growth in energy demand and some evidence of a slowing in the rate of improvement in energy efficiency. For example, small cars on the market today tend to be more powerful, and have more features as standard options which use more energy than was the case in the mid-1980s. Public concern about security of energy supply has lessened since the mid-1980s.

Nonetheless, there is growing concern about the implications for the environment of fossil fuel combustion, and there are certain features of the response to the energy crises of the 1970s and 1980s which have permanently changed the relationship between economic growth and energy demand. Today's energy using equipment differs greatly from that of the early 1970s. The thermal efficiency of both existing and new buildings is much higher than in the 1970s. Building codes ensure that there will not be a reversion to previous, less efficient standards. Energy using equipment, be it household appliances, or industrial equipment, is more efficient than in the 1970s, and efficiency standards have been introduced which will lead to even further improvements. However, consumer attitudes and behaviour with respect to the acquisition and use of energy using equipment, as reflected, for example in thermostat settings, remain major uncertainties which can have large impacts on energy use.

Another measure of energy use is the relationship between energy demand and domestic output. Figure 4-1 shows energy demand and energy **intensity** for the historical and projection periods. This is a measure of energy use per 1981 dollar of Gross Domestic Product. This ratio may decline because energy is being used more efficiently, but it also declines when the mix of output shifts to less energy intensive activities, or when there is a shift from fossil fuel use to electricity. It is not, therefore, a measure of the **efficiency** of energy use. Energy efficiency may be described as the amount of energy required to perform a specific task, for example: to heat a house of a specific size to a specific temperature, or to drive a certain distance, or to manufacture a specific quantity of a well-defined product. Energy efficiency is said to improve if the amount of energy used to perform these tasks decreases. As soon as the energy-using tasks are aggregated into a single measurement, for example, expressing output in constant dollars rather than in physical units, or aggregating the output of

Figure 4-1

Energy Intensity and End Use Energy Demand



Note: End use energy demand is in petajoules; Energy intensity is end use energy demand per unit of 1981$ real GDP, indexed to 1965.

several industries or choosing a denominator such as households (which ignores the fact that house sizes can change, or that the amount of energy using equipment in a home can change), one is capturing the effect on energy intensity of a number of factors in addition to efficiency, rather than efficiency change alone. In the sectoral discussions which follow in this Chapter, to the extent possible, we focus on the specific uses of energy which give rise to total end use demand in that sector. Energy intensity for each sector, and in aggregate, is a result of all of these specific sectoral considerations, as well as of any shifts in the output mix of the economy.

In the last Report we measured economic output in 1971 dollars. Statistics Canada has rebased its activity measures to 1981 (and more recently to 1986) dollars. In this Report we have used a 1981 dollar measure of economic activity. At the same time as it rebased its data, Statistics Canada revised its historical data, in some cases increasing the level of economic output in certain years from previous estimates. As a result, when we examine historical trends in energy intensity, we see different patterns than we did using the 1971-based data. This can be the result of changes in the weightings of the components and does not necessarily mean that we used energy differently than we previously thought.

The pattern of energy intensity has been one of fairly steady decline since the mid-1970s. From 1976 to 1986 energy intensity declined by 2 percent a year on average (this compares to 1.5 percent average decline using 1971-based output data). Since 1986 the average rate of decline has also been about 2 percent per year, despite the fact that intensity increased in 1988 and 1989. Each of these years was significantly colder than the previous, and as the end use data is not adjusted for weather conditions, this could partially explain the change in trend.

4.1 Uncertainties in Projecting Energy Demand

Our Control Case projections are based on a specific outlook about the overall growth rate of economic activity and its distribution between energy-intensive and other industries. All projections are subject to considerable uncertainty, relating

both to individual assumptions and to the way in which they are combined in a single scenario. For example, there is uncertainty about energy prices, about economic growth and the distribution of economic activity between goods and services and across regions; and there is some uncertainty as to how these can be related in a single macroeconomic outlook. It is possible, for example, to achieve a specific economic growth rate with high or low energy prices depending on what other factors affect economic growth, and the outlook for these factors. Another major area of uncertainty is efficiency of energy use which depends on technological developments, the rate of return on investment in energy efficiency, consumer behaviour and choice, the importance of energy costs to production processes and government policies related to energy use.

In the discussions of the sectoral outlooks for end use demand, we review the major uncertainties related to each sector with respect both to the level of demand and fuel shares. The Control Case should not be viewed as the most likely outcome, but rather as one in a range of possible projections of energy demand. In Section 4.5, we review the impact of some specific assumptions on our projection and provide a range around the Control Case results to reflect the many uncertainties of the projection.

4.2 End Use by Sector

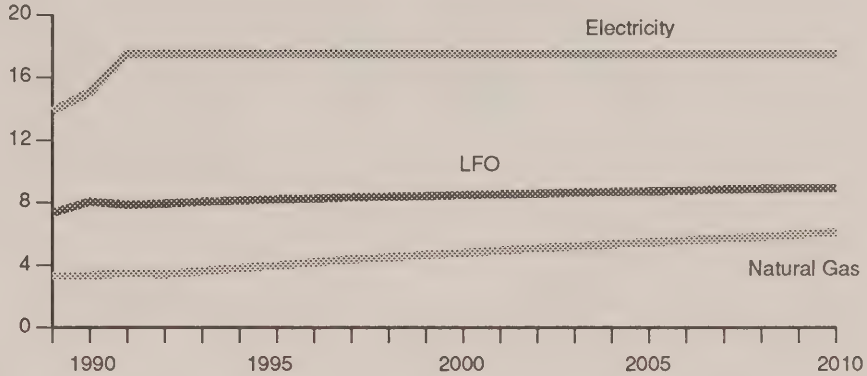
4.2.1 End Use Energy Prices

End use energy prices are burner-tip prices paid by ultimate consumers. They include refinery, transportation and distribution margins, and taxes. In Chapter 2, we

Figure 4-2

Alberta Residential Energy Prices

(1990$C/GJ)

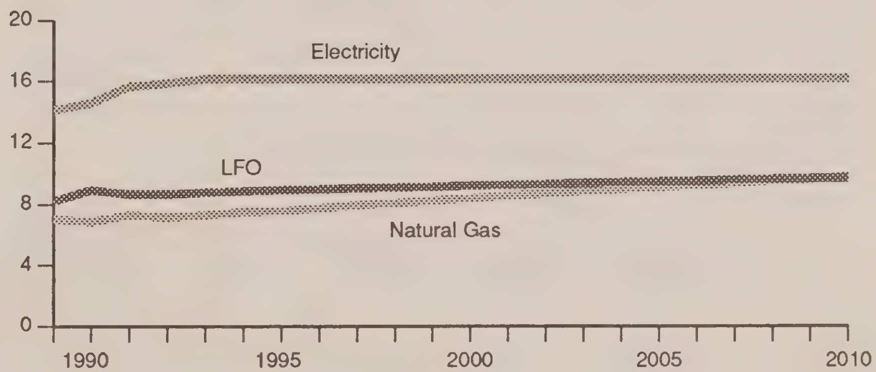


Source: Appendix Table A4-1.

Figure 4-3

Quebec Residential Energy Prices

(1990$C/GJ)

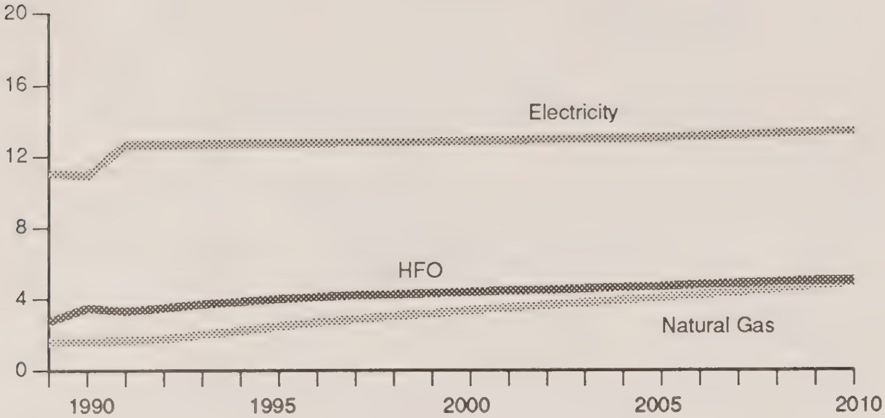


Source: Appendix Table A4-1.

Figure 4-4

Alberta Industrial Energy Prices

(1990$C/GJ)

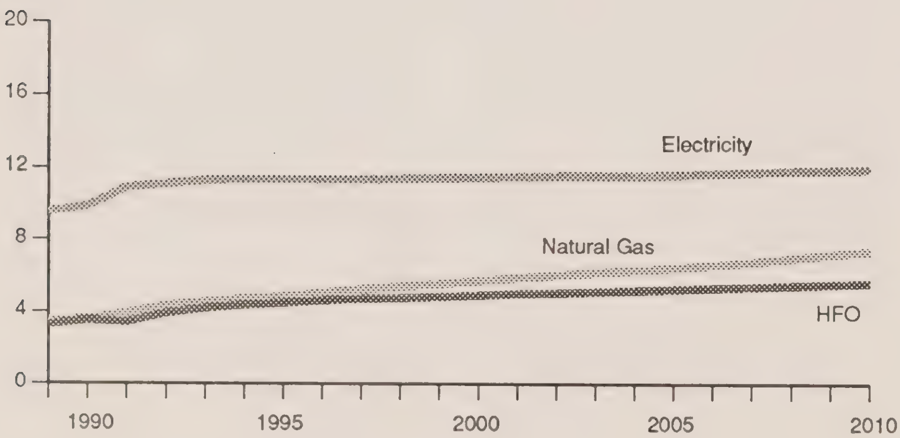


Source: Appendix Table A4-1.

Figure 4-5

Quebec Industrial Energy Prices

(1990$C/GJ)



Source: Appendix Table A4-1.

described how we arrived at our world oil price projections. In Chapter 3, we discussed the derivation of end use natural gas and electricity prices. In this section, we explain how end use prices are calculated for oil products and review the trends in end use prices over the projection period.

Because energy prices vary by fuel and by sector, as well as by region, it is difficult to draw specific conclusions based on national average prices by sector, but some general trends do emerge. Figures 4-2 to 4-5 show Alberta and Quebec end use prices for the residential and industrial sectors. The major difference between the regions is in the delivered price of natural gas.

Table 4-1 presents average burner-tip energy prices in 1990 dollars by sector, for Canada. These prices were derived by weighting provincial or regional prices by each region's share of national demand. These are the prices which consumers pay; they do not reflect the cost of energy per unit of energy output, as this measure would require a further cost increase to account for the losses associated with the conversion efficiency of end use equipment from energy input to work done. Detailed prices by region are shown in Appendix Table A4-1. In the sectoral discussion which follows below, we review regional price relatives.

For **oil**, end use price trends are somewhat different from the trend in crude oil prices discussed in Chapter 2. Refinery margins, transportation charges, distribution costs and taxes account for more than 50 percent of the delivered price of light fuel oil, gasoline and diesel. For these products we assume that refinery margins,

Table 4-1

Average Burner Tip Energy Prices

($C 1990/Gigajoule)

	1989	1990	1995	2000	2005	2010
Residential						
Natural Gas	4.78	4.65	5.31	6.11	6.75	7.36
Light Fuel Oil	8.29	9.05	9.14	9.41	9.67	9.88
Electricity	14.86	15.17	16.99	16.96	16.95	17.22
Commercial						
Natural Gas	4.06	3.99	4.62	5.45	6.09	6.73
Light Fuel Oil	7.00	7.76	7.78	8.04	8.30	8.50
Electricity	18.81	18.82	22.66	22.63	22.61	23.04
Industrial						
Natural Gas	2.43	2.61	3.51	4.38	5.05	5.81
Heavy Fuel Oil	2.92	3.52	4.30	4.70	5.00	5.32
Electricity	10.48	10.81	12.47	12.56	12.69	13.24
Motor Gasoline (cars)	15.90	17.93	18.36	18.83	19.29	19.68
Crude Oil - Edmonton ($C 1990/cubic metre)	138.63	173.94	164.08	174.39	184.39	192.14
Crude Oil - Edmonton ($C 1990/GJ)	3.60	4.52	4.26	4.53	4.79	4.99

Note: Prices are not adjusted for relative fuel efficiencies.

transportation and distribution costs increase at the rate of inflation over the projection period. We have included the GST in all end use energy prices. Taxes for products are assumed to remain at their most recent level in real terms with one exception. For gasoline and diesel, we have adjusted the excise tax, such that the excise tax and GST is equivalent to the previous federal sales and excise taxes. These taxes stay constant in real terms throughout the projection period. As taxes and margins are a large percentage of the delivered price of refined petroleum products, the end use price rises less rapidly than does the crude price for these products.

For heavy fuel oil, we have taken the present price relationship between heavy fuel oil and crude of approximately 76 percent and increased it gradually to 93 percent by 1993. Although the ratio of heavy fuel oil to crude prices has varied over the past, the average has tended to be in the range of 85 percent or higher. Based on discussions with industry, concerning future refinery configuration and production of heavy fuel oil, the 93 percent ratio is in our view a reasonable level, although the ratio could clearly be lower or higher, depending on specific market situations. Given increasing environmental concerns and legislation to reduce sulphur emissions from heavy fuel oil combustion in some provinces, we further added a premium to the price of heavy fuel oil, effectively representing either a shift in the quality of oil used or the cost of desulphurizing heavy oil. The premium is the same as that used in our natural gas analysis (discussed in Section 6.2.10), the equivalent of $0.75 (U.S. 1990 dollars per barrel). To reflect this, the ratio of heavy fuel oil to crude oil was further increased from the 93 percent level in 1993 to 97.5 percent by the year 1997. This ratio was then held at this level to 2010.

In the Low Case in the 1988 Report, one of our hypotheses was that natural gas prices would be differentiated across consuming sectors, in order to keep the natural gas price competitive with

the price of heavy fuel oil in the industrial sector. The effect of this was to have lower gas prices in the industrial sector, and higher prices in other sectors, than would have been the case had the "differentiation" assumption not been invoked. In this Report, we have assumed that competitive conditions in the market would not permit the large differences in price across sectors necessary to maintain the industrial price of natural gas in Eastern Canadian markets at parity with the price of heavy fuel oil. If the industrial natural gas price to Eastern industrial users were maintained at parity with heavy fuel oil, the price differential between industrial and residential and commercial consumers would have to increase over time, to levels well in excess of the current differential. There are now a large number of buyers and sellers in the Canadian natural gas market. This is expected to continue to be the case in the future, and resulting competition would tend to equalize prices for the same contractual terms and conditions. We do not believe that it is reasonable to assume that large commodity price differentials between the industrial and residential and commercial sectors could be sustained over an extended period of time.

In the residential sector the delivered price of natural gas rises more rapidly than that of either light fuel oil or electricity. This happens because the wellhead price of natural gas increases at a higher rate than crude oil or electricity prices (see Chapter 6). However, natural gas maintains its competitive advantage relative to both fuels, taking into account relative fuel efficiencies, in all regions, throughout the projection period. Light fuel oil is not an important residential fuel except in the Atlantic region, hence the major competition in this sector outside the Atlantic is between natural gas and electricity. In the commercial sector, relative price behaviour is similar to that of residential.

In the industrial sector, relative prices vary considerably by region. Transportation and distribution margins account for a large percentage of the delivered price of natural gas to Eastern Canada. As a result, although natural gas to industrial users close to the Alberta wellhead is less expensive than heavy fuel oil throughout the projection period, this advantage erodes in other regions to varying degrees.

- In Manitoba and Saskatchewan, natural gas and heavy fuel oil prices reach parity in the year 2005, and by 2010 natural gas prices are about 10 percent higher. Saskatchewan prices are assumed to be equivalent to the delivered price of natural gas from Alberta. It is possible that Saskatchewan's own supply of natural gas could be lower cost in the province, but we do not feel that this would significantly affect the demand results.

- In British Columbia, parity of gas and heavy fuel oil is achieved by the turn of the century and by 2010, natural gas is just over 10 percent more expensive than heavy fuel oil. Transportation and distribution margins in British Columbia are somewhat higher than in Alberta, with the result that even though British Columbia has its own natural gas supply, end use prices are somewhat higher than in Alberta.

- The relationship in Ontario and Quebec is quite different. In Ontario, natural gas is at about 85 percent of the heavy fuel oil price in 1990, reaching parity in the year 2000, but exceeding it by 20 percent by the year 2010. In Quebec, natural gas and heavy fuel oil prices are currently close to parity. The gap grows to almost 20 percent in favour of heavy fuel oil by the turn of the century, and to 30 percent by 2010. The major difference between Ontario and Quebec industrial gas prices is the larger distribution margin for Quebec consumers than is the case for Ontario.

4.2.2 Residential Sector

This section examines the results of our projection of residential energy demand taking into account our assumptions on those economic, demographic and structural factors which will determine demand between now and the year 2010. We begin by outlining the factors affecting energy demand and then discuss the relationship between these factors and residential energy demand growth since the first oil price shock. We conclude with our projection, for the period 1990 to 2010, based on an analysis of our assumptions and their impact on residential energy demand.

Residential energy demand includes the energy used by all Canadian households (including diesel fuel used in agriculture) except for motor gasoline. During 1989 residential energy demand increased by 90 petajoules to 1492 petajoules, 6.4 percent over its 1988 level. However, this increase in demand should be viewed in the context of 1989, when colder temperatures led to increased heating needs. The rate of growth in demand, normalized for weather, was 4.5 percent in 1989 over 1988.

Residential energy demand by end use in 1989 was broken down as follows: 69 percent for space heating, 14 percent for water heating and 17 percent for lighting and the operation of household appliances.

Household energy demand is influenced largely by the following factors:

- ***household characteristics.*** As households constitute the basic unit of consumption, their characteristics and growth affect energy demand. The use of energy-consuming goods in the home is generally shared by members of the household. Changes in the number of individuals in a household and in their age and employment have an effect on the length of time during which the house is occupied during the day, on the intensity with which energy-consuming goods are used and thus on energy needs.

- ***economic factors*** such as household income and energy prices. Depending on their economic preferences, households will allocate their income between savings and the purchase of a variety of goods and services. Changes in household income should thus result in changes in the acquisition of goods, specifically those which consume energy. The choice of the type and size of house is also related to household income. In addition to affecting the acquisition of goods and services, incomes also affect the type and location of activities of households. The range of activities available to a household and the way in which its members choose to participate broadens as income levels increase. Uncertainty over the extent to which households will decide in the future to take part in activities outside the house, results in similar uncertainty with respect to trends in residential energy needs.

- ***technical aspects.*** The characteristics of houses, furnaces and household appliances are also factors which determine household energy consumption. For example, households in multi-family dwellings tend to consume less energy than those in single family homes since multi-family dwellings are generally smaller and have a smaller exterior wall surface than single family homes. The evolution of housing stock by type is therefore a determining factor influencing energy demand. Construction materials and practices determine the characteristics of dwellings. Insulation standards for new housing have increased over time. The design of heating systems and household appliances has also changed in recent decades, as new technologies have made it possible to bring more energy efficient appliances onto the market.

- ***institutional factors.*** The intervention of governments and utilities through the application of standards, education, and promotion and program implementation affects the energy consumption choices available to consumers.

Table 4-2 shows the relationship between residential energy demand growth and the growth in real disposable income per household, real energy prices, and household formation in Canada for the period 1973-2010.

Between 1973 and 1985, energy consumption per household in the residential sector fell by an average of 1.6 percent per year. During this time, real disposable income per household increased at a modest annual rate of 0.7 percent, and households faced annual energy price increases of nearly 5 percent. 1985 was a turning point for residential energy prices. Whereas energy prices increased steadily each year up to 1984, since 1985 households have benefited from falling prices. This decline, combined with stronger growth in real disposable income per household (1.3 percent per year) has led to a stabilization in energy demand per household since 1985, relative to the decline in the earlier period.

Trends in residential energy demand over the last two decades have been affected by structural changes, including:

- the adoption of stricter insulation standards;

- the implementation of energy conservation and oil substitution programs;

- increased market penetration of existing household electric appliances and the introduction of new appliances to the market;

- increased energy efficiency of household appliances and heating equipment;

- a decline in the number of individuals per household. The average household size in Canada has fallen from 3.5 persons in 1973, to 2.8 persons in 1989.

Higher insulation standards in new buildings have had a direct impact on household energy demand in

Table 4-2

Residential Energy Demand

	Average Annual Growth Rates (Percent)				
	1973-1985	**1985-1989**	**1989-2000**	**2000-2010**	**1989-2010**
Households	2.6	2.0	1.4	1.3	1.4
Real Disposable Income Per Household	0.7	1.3	0.1	1.0	0.5
Real Energy Price[a]	4.9	-3.6	1.5	0.7	1.1
End Use Demand[b]	0.8	1.7	0.5	0.5	0.5
Energy Demand Per Household	-1.6	-0.3	-1.0	-0.8	-0.9

	Levels						
	1973	**1985**	**1989**	**1995**	**2000**	**2005**	**2010**
End Use Demand[b] (Petajoules)	1262.7	1386.7	1481.9	1537.3	1565.1	1600.1	1644.7
Demand Per Household (Gigajoules)	197.3	162.7	160.8	152.2	144.3	137.8	132.8

NOTES: The numbers on this table have been rounded.
[a] The energy price is an index of fuel prices for the sector.
[b] Adjusted for variations in weather.

Canada. The vast majority of Canada's existing housing stock (except for multi-family dwellings) was built with a wood frame, covered with a variety of interior and exterior finishes. Housing built prior to the 1960s often had little or no insulation. During the 1970s, provincial building codes began to require minimum levels of insulation in the walls, ceilings and basements of new buildings. In 1978, in view of the increase in energy prices, the National Research Council of Canada (NRC) published in the National Building Code (NBC) a series of measures for conserving energy in new buildings. However, since the provinces have jurisdiction over residential construction, these measures can be considered as recommendations only. A second set of measures to raise insulation standards was published by the NRC in 1983.

Over the past fifteen years, increases in energy prices have prompted many home owners to take steps to save on energy costs. Governments and utilities introduced incentives to achieve the goals of energy conservation and of conversion to other, more plentiful fuel types, in order to

reduce the country's dependence on imported oil. Most of the national programs introduced during this period have since ended. In light of the changes which have occurred in residential construction in recent years, the energy efficiency of new houses in Canada is estimated to be 35 percent higher than that of the overall stock.

The structure of heating fuels also underwent considerable change over the past decade, as a result of both efforts to replace heating oil in existing houses and of the choices made by developers and owners of new homes. Electric heating has increased in popularity. In 1980, 37 percent of households in Canada used oil as their primary heating source, while 39 percent used gas and 19 percent electricity. The breakdown in 1989 was 17 percent, 44 percent and 33 percent respectively for oil, gas and electricity. Other fuels, such as wood and propane, were used as the primary heating source in approximately 6 percent of households.

In addition to the growing popularity of electric heat, changes in the penetration of household appliances have contributed to a shift in the relative importance of various fuels in residential energy consumption. The average household has more energy-consuming appliances now than at the beginning of the 1970s. Among the major appliances, microwave ovens grew most sharply and, although almost non-existent in the mid 1970s, were present in nearly 65 percent of Canadian households in 1989. Between 1975 and 1989, significant increases were also observed in the penetration of freezers (from 42 to 59 percent), dishwashers (15 to 43 percent) and electric dryers (from 48 to 71 percent). The penetration of clothes washers remained relatively stable at around 78 percent. During the same period, the penetration of colour televisions also increased appreciably. In many cases, the colour televisions replaced black and white sets which use about 33 percent less electricity than a colour set. In recent years, the type of new appliances acquired by consumers has also changed. The new appliances are mainly electronic entertainment or work equipment such as video cassette recorders, compact disc players and personal computers, which tend to consume small amounts of energy. However, their acquisition also contributes to a change in the way people spend their time in the home and thus in household energy needs.

In a typical household today, the major household appliances (refrigerators, freezers, dishwashers, clothes washers and electric stoves) are more energy efficient than they were in 1973. Technological changes have enabled manufacturers to market new appliances which are now 30 to 55 percent more efficient than those in the early 1970s. Significant gains in the fuel utilization efficiency of conventional gas and oil furnaces were also achieved in the late 1970s and resulted in an average efficiency level of approximately 65 percent. Gas and oil heating systems with efficiency levels of from 80 percent to over 90 percent have since been introduced on the market.

According to the Canadian Gas Association, sales of conventional (less than 80 percent efficient), mid efficiency (between 80 and 89 percent efficient) and high efficiency gas furnaces (more than 90 percent efficient) as a proportion of total new gas furnace deliveries have remained steady at approximately 67 percent, 10 percent and 23 percent respectively since 1984. The use of heat pumps for space heating and cooling represents a relatively recent application of a known technology. Refrigerators and air conditioners are two examples of heat pumps which operate only in the cooling mode. This technology is installed in only 2 percent of Canadian homes for heating and cooling purposes. For heating needs, the efficiency factors (or seasonal performance coefficients) vary between 120 and 270 percent, depending on the type of equipment used and the climatic extremes in the region where the heat pump is used. An efficiency factor of 270 percent means that there is a heat transfer of 2.7 kW.h per kW.h of electricity supplied to the heat pump. The greatest disadvantage remains its inability to satisfy all heating needs because, in most regions of Canada, the outside air temperature drops to levels where the heat loss from dwellings exceeds the amount of heat supplied by the heat pump. The heat pump should therefore be supplemented by another system, and as a result the potential savings are often too low to make the investment worthwhile. Given energy prices in Canada, the payback period for a heat pump may exceed ten years.

Our projection of residential energy demand for the period 1990 to 2010 is based on the following demographic and economic assumptions:

- The number of households will grow at a slower rate than in the past. Between now and the year 2000, the annual rate of growth will remain stable at 1.4 percent. Over the following ten years, household formation will slow gradually and the

average annual growth rate for that period will be 1.3 percent.

- The number of households will grow faster than the population and the average size of Canadian households will decline from 2.8 persons in 1990 to only 2.5 in 2010.
- Real disposable income per household will increase only slightly through the 1990s and will grow at an annual average rate of 1.0 percent between 2000 and 2010.
- After declining since 1985, real energy prices will increase beginning in 1990 at a rate slightly above one percent per year until 2010.

With respect to the thermal efficiency of existing houses, it would appear that, given our fuel price assumptions, for most of the country any measures aimed at increasing the level of insulation would be economic only for uninsulated houses (typical of construction prior to 1945) and for electrically heated houses with little insulation. We believe that there is some potential for energy savings through additional measures to insulate the existing housing stock. However, we have assumed that, in the absence of major incentives in this area, there will be no significant improvement in the energy efficiency of existing housing during the projection period. The gradual replacement of the existing stock by new, more energy efficient, dwellings will contribute to the decline in average consumption.

Announced changes to regulatory standards in residential construction and the use of better insulating materials are expected to result in a steady improvement in the energy efficiency of new housing during the projection period. Given trends in the construction of single family and multi-family dwellings, the unit consumption of new housing declines by approximately 8 percent by 2010. New construction adds to the existing housing stock at a rate of some 240 000 units per year. At this rate, dwellings built since 1984 will represent almost 50 percent of the total housing stock by 2010. The NRC's committee on the National Building Code is scheduled to publish a revised version of energy conservation measures in new buildings in 1991. (The new standards had not yet been published at the time of writing). Amendments to British Columbia's building code are planned for 1992 and are expected to include standards for reducing energy costs through the adoption of economically viable measures. In Ontario, the updating of the provincial building code is expected to lead to a 15 percent reduction in heating requirements for new single family dwellings from 1991 on, relative to houses built to the standards in effect in 1990.

The energy efficiency of new houses can be improved considerably, with currently available technologies for products such as windows and doors, and if more attention is paid to increasing the insulation level, to preventing air leaks and to selecting the location based on solar orientation. However, given the low level of energy prices in our projection for the residential sector and also the desire to limit construction costs, we do not believe that builders will show strong interest in integrating a wide range of new energy efficient technologies in new houses. Similarly, we do not anticipate sufficient interest in energy savings to prompt a significant increase in demand for R-2000 houses or for those with even more advanced energy efficiency characteristics. The payback period required to recover the additional investment in such houses exceeds the length of time most home owners live in one house. It also appears that few house purchasers value the advantages inherent in living in an R-2000 house, which incorporates many energy efficiency advances. These barriers notwithstanding, some energy efficiency initiatives for new housing will be sustained by utilities' demand management programs.

We anticipate some improvement in the average energy efficiency of heating systems and assume that during the projection period the average energy efficiency of the stock of gas furnaces will increase by about 8 percent. This improvement results primarily from an anticipated improvement of almost 10 percent in the efficiency of new systems in use, as a result of an increase in the penetration of mid efficiency systems. We assume that, beginning in 1992, the penetration of mid efficiency systems will increase to 75 percent, while the rate for high efficiency systems will remain at a level close to that of the 1980s, about 25 percent.

In response to regulations made under Ontario's Energy Efficiency Act which set point-of-sale standards, manufacturers have said that they will support the production of gas heating systems with an efficiency of 78 percent beginning in January 1992. We have assumed that this standard will be implemented nationwide. We project an average improvement in the efficiency of the oil furnace stock of 4 percent by 2010, due to the removal of the oldest, inefficient equipment and the replacement of a portion of these with new, more efficient oil furnaces.

The projected improvement in the thermal resistance of new housing envelopes will likely reduce the attraction of heat pumps by extending the payback period. During the projection period we anticipate that the penetration of gas heating should remain relatively constant at approximately 45 percent, the proportion of households heating with oil will drop sharply to about 6 percent in 2010 (from 17 percent in 1989) and the popularity of electric heating will increase to about 42 percent (33 percent in 1989). Some 7 percent of households will use another primary heat source during the projection period, especially wood or propane.

With respect to water heating needs, we believe that, despite the projected increase in the penetration of dishwashers, the combined effect of the decreasing size of households and improvements to new dishwashers and washing machines (due to features which allow for better control and a reduction in hot water consumption) will result in a decrease of nearly 12 percent of hot water needs per household by 2010. Combined with an improvement in the efficiency of hot water heaters, (partly as a result of utilities' demand management programs), we expect that average energy use per household for water heating will decrease by some 16 percent during the projection period.

It appears likely that, during the projection period, improvements in the efficiency of Canadian household appliances will be driven to a large extent by technological developments in the United States. Unit consumption of household appliances has historically been lower in the United States than in Canada, partly because lower energy prices in Canada have not generated a demand for increased energy efficiency in appliances. The investments required by Canadian manufacturers to improve their products have often not been considered economically viable due to the relatively small size of the domestic market.

The Free Trade Agreement between Canada and the United States will open the Canadian household appliance market to greater competition. The largest Canadian manufacturers are affiliated with the major American producers of household appliances and rely to a large extent on American firms for product design and innovation. Higher energy prices, strict efficiency standards and the large amount of research and development in the United States will contribute to technological improvements in the energy efficiency of household appliances.

The standards governing the energy consumption of refrigerators and freezers are expected to be tightened in 1993. The new standards should lead to a decline of approximately 25 percent in unit energy consumption for new refrigerators/freezers relative to the existing standards. Revised standards are also expected in 1995 for clothes washers, dryers and dishwashers. The Government of Ontario has agreed, pursuant to its Energy Efficiency Act, to increase standards for refrigerators and freezers effective in 1994. The new standards should be as high as those scheduled to take effect in the United States in 1993. Ontario also plans to adopt the existing United States standards for electric stoves, dishwashers, washers and dryers. Given the weight of the Ontario market in the Canadian economy, we believe that the standards adopted by the Government of Ontario could determine the energy efficiency of household appliances across Canada. In this context, we assume that by 2010 the average improvement in the efficiency of household appliance stock will be as follows:

Refrigerators	53 percent
Freezers	60 percent
Dishwashers	17 percent
Clothes washers	25 percent
Dryers	12 percent
Electric stoves	23 percent

We believe that growth in sales of household appliances will remain fairly constant during the projection period, due to the replacement of aging appliances. Microwave ovens and dishwashers will experience the largest increase in their penetration rates.

It is estimated that Canadian households use incandescent light bulbs for 90 percent of residential lighting. Energy needs per light bulb can be reduced by between 70 and 80 percent by using compact fluorescent lights where appropriate. Under situations of intensive use, the adoption of compact fluorescents can be economic within the investment horizon of most consumers. For example, given our projected electricity prices, with three hours of use per day, it takes an average of five years for a Canadian consumer to recover the additional cost of a compact fluorescent unit, as compared to the alternative use of incandescent bulbs. Although this type of fluorescent light fits the sockets normally used for incandescent bulbs, its acceptance remains uncertain due to its weight and size, and consumer response to its high price. Our energy demand projection assumes an improvement in the average efficiency of residential lighting of about 15 percent by 2010.

Based on these assumptions, total residential energy requirements to operate household appliances and lighting should increase by slightly more than 5 percent by 2010, relative to 1989 needs. Significant improvement in the efficiency of household equipment is the major factor underlying this modest increase in energy needs.

In brief, taken together, the considerations outlined above lead to an increase in residential energy demand of approximately 11 percent (an annual average growth of 0.5 percent) during the projection period. Annual household consumption should fall by 17 percent (an annual decrease of 0.9 percent) by 2010. Space heating needs account for over 60 percent of this efficiency improvement, as a result of the addition of new houses to the housing stock, and as a result of the replacement of old heating systems with more efficient ones, and the increasing popularity of electric heat. Approximately 15 percent of the efficiency improvements result from measures related to water heating and 25 percent from improvements to the efficiency of lighting and household appliance stock.

The electrical utilities in Quebec, Ontario and British Columbia have implemented demand management programs which will affect energy demand and intensity in the residential sector. Our energy demand projection takes into account the impact of these programs. We estimate that, in the absence of such initiatives, energy needs in the residential sector would be 33 petajoules (or 2 percent) higher in 2010 than in this outlook.

The long run average growth rate of residential energy demand, of 0.5 percent per year in this projection, is slightly lower than that in the high case of our 1988 Report. In that Report we projected average annual growth in demand ranging between 0.6 and 0.8 percent, for the high and low cases respectively. Despite the fact that the actual energy demand in 1989 was some 6 percent higher than we had estimated for that year in our 1988 projections, greater improvements in this outlook in the energy efficiency of domestic appliances and in the thermal efficiency of new housing results in residential demand in 2005 at close the level projected in the low case of the 1988 Report.

There is a degree of uncertainty surrounding all energy demand projections. In this outlook, we believe that changes in the lifestyles of individuals could have a significant impact on residential energy demand. Given an aging population, it is possible that, on the one hand, a growing proportion of Canadians will choose to spend more time at home, thereby increasing residential energy needs. On the other hand, a larger segment of the population might prefer to participate in more activities outside the home, such as travelling, for example. Increasingly sophisticated methods of communication could encourage the growth of professional activities in the home. Variations in the predicted life expectancy of household equipment and in its penetration and utilization could lead to changes in energy demand relative to our outlook. Finally, the degree to which demand side management programs succeed in meeting established objectives is another area of uncertainty. These programs are designed to promote energy conservation. The purchase of appliances with energy efficiency enhancing features often involves additional costs at the time of acquisition. Studies of the purchasing habits of consumers, however, have revealed that they like to recover the additional amounts invested within a relatively short period (generally about one year) through lower operating costs. A lower acceptance rate than forecast for high energy efficiency equipment would result in energy demand higher than projected in this outlook.

4.2.3 Commercial Sector

Commercial sector energy demand includes the requirements of the institutional sector and all service industries except transportation and energy utilities. This sector is made up of a wide variety of building types, with diverse energy needs including schools, hospitals and other health-related buildings, religious and institutional buildings, office buildings, retail establishments, hotels, motels and restaurants, recreational buildings, warehouses and other service establishments such as laundromats. Within these categories the largest energy users are: offices, which account for about 21 percent of commercial energy use; and retail stores, and educational buildings which each account for 18 percent of the sector's energy use. The energy shares of each of the remaining building types are 10 percent or less.

Energy use in the commercial sector is in many respects similar in nature to the residential sector and may be characterized under five broad categories:

- **Space heating** is the largest single energy use in most commercial building types, although not as dominant as in residential buildings. It is esti-

mated that space heating presently accounts for about 55 percent of commercial energy use. Natural gas is used in two thirds of commercial space, followed by oil and electricity. Heating systems vary according to the size and type of building. Gas, oil and electric boiler systems are all used in large buildings, but gas-fired boilers predominate. For smaller buildings, in addition to boiler-based heating systems, there is significant use of gas-fired rooftop units and electric heating systems.

- **Lighting** accounted for almost 15 percent of commercial energy use in 1988. However, lighting represents one-third of commercial electricity use. Lighting intensity in most existing commercial buildings (2-3 Watts per square foot) is generally regarded as unnecessarily high for most applications. It is usually provided by standard 40 Watt fluorescent bulbs in two or four bulb luminaries with conventional core ballasts. While the technical and economic potential for both lower lighting levels and more efficient technology has been well established, these new technologies are not extensively used in existing buildings for reasons discussed below.

- **Cooling** refers to electricity used to run central and unitary air conditioning equipment but not the fans that move the air. Large buildings typically employ central cooling systems that are integrated with the building's HVAC (heating, ventilation, air conditioning) design and which use refrigerant compressors to produce chilled water which in turn is used to cool building air. Most cooling systems are electric, although there are some gas units.

- **Ventilation** refers to the fan motors that are used in building HVAC systems to provide clean air and distribute conditioned air throughout the building space.

- **Equipment** encompasses the wide range of other electric uses in commercial and institutional buildings, primarily the "plug" load, but also service motors for elevators and other electrically-powered building systems which are not part of the lighting or HVAC systems. This category also includes restaurant cooking energy and hot water requirements. The intensity of the plug load has been increasing rapidly in some building types due to the proliferation of modern information processing technologies.

For commercial consumers as a whole the relative importance of each use differs from that in the residential sector.

A summary of the historical pattern of commercial energy use, prices and economic activity appears in Table 4-3. During the 1973 to 1985 period commercial sector energy demand grew by 1.2 percent per year as the influence of energy prices, which were rising by over 4 percent annually in real terms, was more than offset by growth in commercial sector real GDP, which increased by close to 3.5 percent per year. From 1985 to 1989 commercial real GDP grew faster than in the earlier period, and energy prices declined in real terms, as oil prices weakened and gas prices showed only slight increases. Commercial energy use grew on average 2 percent per year. During the entire period 1973 to 1989, energy intensity (energy per 1981 dollar of commercial GDP) in this sector declined by almost 2 percent per year.

There are several areas of significant uncertainty in a projection of commercial sector energy use:

- the outlook for real GDP and the service sector share of the output; some analysts expect a rapid increase in the service sector share of Canada's output over the next twenty years, while others expect it to stabilize as a result of the growing saturation of the market for various kinds of services and the fiscal squeeze on government-provided services;

- the thermal efficiency of new construction in the commercial sector and the specific characteristics of "new" versus "existing" buildings (e.g. is air conditioning more prevalent in new buildings?);

- the extent to which a wide range of electricity-using office equipment will be used more extensively and the associated efficiency of this equipment; this is the so-called "plug" load, discussed in more detail below; and

- the rate of penetration of new energy efficient technologies, particularly those which are currently available and cost-effective under today's energy prices but are not experiencing wide-scale use as a result of barriers discussed below; in the commercial sector, lighting technologies are the best example of this phenomenon.

Among the barriers to investment in energy efficiency or conservation in the commercial sector are:

Table 4-3

Commercial Energy Demand

	Average Annual Growth Rates (Percent)				
	1973-1985	1985-1989	1989-2000	2000-2010	1989-2010
Commercial Real GDP	3.2	4.0	2.0	2.1	2.0
Real Energy Price[a]	4.4	-2.3	1.9	0.6	1.3
End Use Demand	1.2	2.0	1.0	1.0	1.0
Intensity	-1.9	-1.9	-0.9	-1.1	-1.0

	Levels						
	1973	1985	1989	1995	2000	2005	2010
End Use Demand (Petajoules)	711.9	821.3	889.4	948.4	996.6	1048.0	1100.0
Intensity (Megajoules per $C 1981)	6.5	5.1	4.8	4.5	4.3	4.1	3.9

NOTES: The numbers on this table have been rounded.
[a] The energy price is an index of fuel prices for the sector.

- focus on first cost, that is the initial capital costs (which are usually lower, although with less efficient energy consumption standards and higher operating costs), rather than life-cycle or operating costs (the initial capital cost may be higher, but with more efficient energy consumption standards and lower operating costs the life-cycle costs are lower): for example, large owners who lease their space and can pass energy costs on to their tenants are more likely to be concerned about first cost when erecting new buildings;
- the owner/occupancy structure of a building: government and large corporate owners, occupying their own buildings, are the most likely to undertake energy efficient investments; small owners/leasers are less disposed to undertake energy-saving investments;
- lack of awareness of efficient technologies and systems; and
- appearance and aesthetics may take priority over energy efficiency.

Our projections of commercial sector energy demand are influenced by commercial sector GDP growth, changes in energy prices, government and utility policies, and the extent to which energy saving technologies are likely to be

implemented. These are discussed below. Given the diversity of the commercial sector, the requirement for very large amounts of detailed data and information to carry out a detailed analysis of energy use by building type and end use, and the lack of readily available, reliable data, we have to a large extent focussed on the energy requirements of large energy users - particularly the energy requirements of office buildings, and on a review of some specific energy end uses, including lighting and plug loads.

Over a 20-year outlook there is some turnover of capital stock, both equipment and buildings. This in itself will dampen growth in energy demand even if there were no further technological improvements beyond those available today. It is estimated that, for new all-electric **office buildings,** space heating requirements are about 30 percent lower than for existing structures. Lighting and ventilation needs are about 14 percent lower. However, increased penetration of air conditioning, even with more efficient systems, raises the energy use for cooling for an "average" new building to over 80 percent above that of the existing stock. For all end uses combined, a new all-electric office building uses about 13 percent less energy than existing stock. New retail (all electric) buildings are estimated to be about 10 percent more efficient for each of HVAC, refrigeration and lighting.

State of the art building designs can result in even lower energy use than what is currently considered the norm for new construction. For example, courthouses in Newmarket and Ottawa, Ontario are examples of state of the art construction. Inclusive of tenant loads, such buildings consume about 0.8-0.9 gigajoules per square metre, compared to 1.2 or 1.3 gigajoules per square metre for more conventional new buildings, or a 33 percent improvement.

The energy needs associated with **lighting** are the subject of much discussion. There exist several energy saving and cost effective technologies which are not widely used in commercial establishments. During the 1970s and 1980s energy savings were realized through reducing illumination levels by removing existing lamps. This achieved wide-spread acceptance, and does not offer much possibility for further efficiency gains. Over the twenty years of our projection period energy savings in lighting are expected to occur by increased use of new technologies, especially because it is likely that all existing lighting fixtures will undergo at least one complete replacement during the next twenty years.

Among the existing fluorescent lighting technologies which offer improved efficiency and a short payback when compared to the standard 40 Watt lamp with standard 16 Watt ballast and white painted metal fixture are:

Technology Type	Percent Energy Saving
Energy saving replacement lamps	15
Higher energy saving replacement lamps	20
High energy saving new installation lamps	20
Energy efficient core and coil ballast	10
Electronic ballasts	15 to 40
Electronic ballasts with dimming functions	50 to 80
Optical reflectors (with removal of half of the lamps)	50

In summary there is considerable potential for large efficiency gains from adoption of more efficient lighting technologies. However, as noted above, there are equally large barriers to be overcome despite the generally favourable returns of many of these investments.

Of major concern to all electric utilities is the current size and likely rate of growth of the poorly understood "other" end use category, which includes commercial **plug loads**. Of particular importance in this category is office use of electronic equipment for information storage, processing, production and transmission. Future load growth of this category depends critically on three assumptions: the rate of penetration of this equipment, the usage and service level (i.e. computing power) and its energy efficiency. A number of factors make this an extremely complex subject to analyze:

- It is estimated that the nameplate ratings of personal computers and other office equipment may overstate actual measured power by factors of 2-4 for personal computers and 4-5 for printers. This is important if nameplate ratings are used to project electricity demand.

- There are wide variations in power usage across existing equipment. For example, desktop models use about ten times the power of equivalent laptop computers. Laser printers require five to ten times the power of impact printers, and are growing in popularity as their costs come down. Colour and high resolution monitors, which are also experiencing increased penetration, use up to twice the power of a monochrome monitor.
- There are clearly many opportunities for efficiency gains with today's technology, even for those applications which are relatively energy intensive and growing in popularity (such as laser printers). However, it is not clear whether such improvements will be implemented, nor what the offsetting impacts will be of a desire for more powerful machines, continued penetration of office equipment in new areas, or rationalization of existing uses (e.g. trends to a "paperless" office).

To place some perspective on the magnitude of this issue, it has been estimated that for the United States, office electricity use in 1995 could range between 25 TWh, close to the estimated level for 1988 (if the most efficient existing hardware were the norm)[1], and over 115 TWh (assuming market saturation of most commonly used current technology and expanded use of computerized printing).

Economic growth of the commercial sector influences floor space requirements and related lighting and space conditioning needs, as well as energy uses not related directly to floor space arising from larger amounts of office equipment. The precise relationship between floor space and real GDP is difficult to determine, as it will vary by building type. Moreover as productivity gains are realized in certain sub-sectors, floor space will not grow as rapidly as output, but will more closely reflect employment growth.

In our Control Case **commercial sector real GDP** grows at about 2 percent per year from 1989 to 2010, somewhat more slowly than output of the goods sector. By itself, GDP growth leads to higher energy demand, although the precise relationship will depend on the mix of growth, the rate and source of productivity improvements, and the rate of capital stock replacement.

As noted earlier, commercial sector energy demand will also be influenced by changes in energy prices, by government and utility policies such as demand-side management, and by the extent to which barriers to the adoption of energy-saving technologies are overcome.

Energy prices to this sector rise in real terms at a rate of about 2 percent per year until 2000, reflecting large increases in real electricity prices until 1993 and growth in real natural gas prices throughout the decade. From 2000 to 2010 real energy price growth moderates to an average annual rate of 0.6 percent.

With regard to demand-side management, we expect commercial sector electricity demand in 2010 to be about 1 100 petajoules; this is about 42 petajoules lower than it otherwise would be, due to the implementation of **demand management** programs in Quebec, Ontario and British Columbia.

As mentioned earlier, there are significant barriers which must be overcome to facilitate the **penetration of energy-saving technologies** in this sector. Our projection takes into account the estimated turnover of existing equipment and capital stock (including buildings) and assumes that these are replaced with technologies consistent with ***today's*** most widely-used, efficient, energy-using capital. New equipment and buildings similarly reflect ***today's*** efficiency levels for new equipment and buildings. This allows for some increased penetration of more efficient lighting technology and some increase in plug load.

Given the assumptions outlined above, in the Control Case commercial sector energy demand grows at an average of one percent per year from 1989 to 2010. With commercial sector real GDP growth at two percent annually this results in an annual decline in energy intensity of one percent over the period. This outlook for intensity decline is consistent with the normal turnover of existing capital stock and increased penetration of new equipment and construction of new buildings, all of which are more efficient than the average stock existing today.

Fuel shares are relatively stable throughout the period. Both electricity and natural gas made major

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1 "Electronic Office Equipment: The Impact of Market Trends and Technology on End-Use Demand for Electricity" in *Electricity - Efficient End Use and New Generation Technologies, and Their Planning Implications*, eds. Thomas B. Johansson, Birgit Bodlund, Robert H. Williams, Lund University Press 1989.

gains in share during the 1970s and 1980s at the expense of oil products. In 1989, electricity accounted for 43 percent and natural gas for 42 percent of commercial end use energy demand. Electricity's share is expected to rise to just over 46 percent by the year 2010, while natural gas maintains its 42 percent share. The price relatives for the sector are such that natural gas maintains a price advantage over electricity throughout the projection period in all regions. Though natural gas prices rise more rapidly than the prices of light fuel oil and electricity in all regions, only in Quebec do natural gas prices become slightly higher than those of light fuel oil by the end of the period. The ultimate fuel choice in this sector depends in part on price relatives (for example, for HVAC decisions), but many commercial uses preclude any fuel other than electricity.

Apart from the uncertainty over commercial sector real GDP growth, the major uncertainties in this outlook, in our view, are the rate of adoption of highly efficient (and currently available) lighting technology (a higher rate of adoption would reduce electricity demand relative to the Control Case), the potential for a much larger increase in the "plug load" (which would increase energy demand relative to the Control Case), and the potential for technological change (which could reduce energy consumption and affect final choices - for example, new applications of fibre optics in computers and telecommunications and innovations in natural gas air conditioning).

As compared to the 1988 Report, this projection falls between the 1988 High and Low cases. By the year 2005, in the Control Case, commercial sector energy demand is 1048 petajoules, as compared to 1031 to 1068 petajoules in the 1988 Report. The rate of decline in energy intensity is comparable, in the range of one percent a year.

4.2.4 Industrial Sector

This section describes the basis for our projections of end use energy demand in the industrial sector.

The industrial sector includes the manufacturing industries, forestry, construction and mining, but excludes the petrochemical industry (discussed in Section 4.2.5). The sector accounts for approximately 35 percent of total end use energy demand. However, most of the energy it consumes is concentrated in a few small but highly energy intensive industries. Table 4-4 shows energy consumption for major industries in 1989.

Pulp and paper is by far the largest energy user; it consumed over 29 percent of the total industrial energy demand in 1989. In 1989 the combined energy consumption of the mining, pulp and paper, iron and steel, smelting and refining, cement and chemicals (excluding petrochemicals) industries accounted for 73 percent of industrial energy demand. However, the output of these industries accounted for only 32 percent of industrial production. The remainder of the industrial sector includes forestry, construction, petroleum refining and other manufacturing, which together account for the other 27 percent of industrial energy demand.

Table 4-4

Intensity of Industrial Energy Use, Levels and Distribution of Total Industrial Energy by Selected Industries in 1989

	Intensity [a]	Petajoules	Percent Share [b]
Forestry	11	35	1
Mining	15	348	13
Total Manufacturing	28	2206	84
Pulp and Paper[c]	115	763	29
Iron and Steel	91	295	11
Smelting and Refining	62	183	7
Cement	35	65	3
Petroleum Refining	107	89	3
Chemicals[d]	46	253	10
Other Manufacturing	10	559	21
Construction	1	40	2
Total Industrial	**19**	**2629**	**100**

Notes: The numbers on this table have been rounded.
[a] Megajoules per 1981 dollar of industrial output.
[b] Share of sub-sector energy demand to total industrial energy demand.
[c] Pulp and Paper and allied products.
[d] Excludes feedstocks used in the petrochemical sector.

Table 4-5

Intensity of Industrial Energy Use by Region in 1989 and 2010

	1989	2010
Atlantic	25.7	19.7
Quebec	19.4	16.0
Ontario	15.0	11.6
Manitoba	15.6	12.2
Saskatchewan	15.4	13.9
Alberta	22.9	30.6
British Columbia	29.7	23.0
Canada	19.2	16.4

Note: Megajoules per 1981 dollar of industrial output.

British Columbia, Alberta, and the Atlantic provinces have a large share of the highly energy intensive industries which results in higher energy intensities for those provinces than for others (Table 4-5).

Industrial energy intensity is the ratio of industrial energy use to industrial GDP. Changes in industrial energy intensity reflect the impact of measures undertaken by industries to conserve energy, but they can also result from changes in fuel market shares, shifts in industrial output between energy intensive and less energy intensive industries, and changes in the level of the industry's output. An industry's capacity utilization rate reflects its level of output relative to its productive capacity. A decline in the capacity utilization rate tends to increase energy intensity, because some energy requirements, such as those related to heating a plant, are independent of the level of production. Occasionally, if an industry expects a short-term downturn in its output, it may elect to maintain certain energy intensive processes, for example pot lines in a smelter, or furnaces in a steel plant, even though output is below capacity, as shutting down these processes and restarting them at a later date can be costly. In this situation, capacity utilization declines but energy intensity may increase.

Energy savings per unit of output, or reductions in energy intensity, are the result of measures implemented by the industry in response to a variety of incentives and risks in the market place. These measures fall into two categories:

- Measures that reduce energy use per unit of output without necessarily affecting the productivity of labour and capital, for example waste heat recovery techniques and use of high efficiency electric motors. These types of measures tend to be driven by changes in average and relative energy prices and by the length of the payback period of the measures.

- Measures that reduce energy intensity because of a change in a particular industrial process, for example continuous casting in steel-making, greater automation and use of computers. These measures are usually independent of energy prices and are implemented as a result of broader considerations related to increasing the general competitiveness of an industry. They can involve processes which use electricity rather than those using other fuels.

Each of these measures has contributed to reductions in energy intensity, and the distinction between these two categories provides a useful framework for analysis of future changes.

Changes in fuel market shares, particularly those which increase the share of electricity, also contribute to reduced energy intensity measured as *end use demand* per unit of output. This can be seen as follows. If a process uses a fuel other than electricity, a conversion loss is incurred at the burner tip; i.e., between the input of the fuel and the output or production of useful energy. Thus more units of end use energy are required as input than are ultimately available to the process. However, if the process converts to electricity, fewer end use units of energy are needed as there is virtually no efficiency loss between the industrial plant's receipt and use of electricity,. In this way, measured energy intensity (end use input units of energy per dollar of output) is reduced when industries substitute electricity for other fuels.[1]

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1 Two comments on this are warranted: first, there are conversion losses upstream in the generation of the electricity which are not accounted for in the end use energy intensity measure, and secondly, the decline in measured intensity from the conversion to electricity need not reflect an actual efficiency gain in terms of the end use output units of energy needed by a process.

Energy prices and economic activity played an important role in determining industrial demand for energy in the 1973 to 1989 period. Some overall energy savings were realized during this period, although it was comprised of two sub-periods characterized by distinct and partially offsetting trends.

The 1973 to 1980 period saw large energy price increases and relatively low rates of growth of labour productivity and investment. Energy intensity increased at a rate of some 2.0 percent per year over this period. Although rising energy prices tended to reduce energy demand and intensity, this was more than offset by an increasing share of output of major energy consuming industries.

In contrast to the 1973 to 1980 period, the 1980 to 1989 period saw more modest energy price growth (despite large fluctuations in price during the period) and much larger variations in productivity and investment. Over this period concern over energy efficiency was overshadowed by broader concerns of economic efficiency and competitiveness. Growth in industrial output, increased capacity utilization and productivity and the lagged impact of increasing energy prices in the latter half of the 1970s and early 1980s led to notable improvements in the efficiency of industrial energy use. Most of these changes resulted from the adoption of new processes, motivated by concerns for competitiveness and productivity, rather than by energy costs. During this period energy intensity fell by about two percent per year on average and energy intensive industries showed above average improvements in energy savings.

Overall trends in aggregate industrial energy demand and intensity mask structural changes which have occurred in energy intensive industries. Major energy-related developments in these energy intensive industries are summarized below, along with the industry-specific developments reflected in our projections of industrial energy use.

The **mining** industry consists of activity in metal mining industries, non-metal mining industries, energy mining, and quarry and sand pit industries. The distribution of mining energy use and intensity across regions reflects the differing mix of this industry regionally, and the variation in energy use within the mining sector.

Although the mining sector is not one of the most energy intensive industries, it accounts for about 13 percent of industrial energy demand. On a regional basis, Alberta accounts for the largest share of energy use in the mining sector in Canada. This share increased from 25 percent in 1978 to 56 percent in 1989, mainly because of the increasing importance of energy mining requirements, particularly bitumen projects.

From 1978 to 1989, energy intensity in mining increased by 43 percent. This resulted from an increase in bitumen production from mining plants and in situ operations, which are very energy intensive. Mining sector energy intensity in all regions except Alberta declined, mainly as a result of better energy management, a greater application of heat recovery methods and the use of more efficient electric motors.

In the **mining** industry, we project a 13 percent overall improvement in energy intensity by 2010 in all regions but Alberta. The savings outside Alberta in energy use are expected to occur from:

- the introduction of more efficient electric motors;
- extensive use of heat recovery technologies; and
- better energy management.

In Alberta, efficiency improvements are masked by the rising requirements of energy mining projects, particularly bitumen. Energy requirements for bitumen projects increase from about 76 petajoules in 1989 to 370 petajoules in 2010.

As mentioned earlier, the **pulp and paper** industry accounts for the largest single share of industrial energy demand. It is also the only industry where by-products of the production process (hog fuel and pulping liquor) themselves provide the largest proportion of energy requirements.

The share of these fuels has increased in recent years at the expense of purchased fuels such as heavy fuel oil, coal and, to a lesser extent, natural gas. Purchased fuels accounted for 350 petajoules of energy demand in 1978 and 374 petajoules in 1989, an increase of only 24 petajoules, while hog fuel and pulping liquor consumption increased by 102 petajoules, from 287 petajoules in 1978 to 389 petajoules in 1989, 51 percent of this industry's total energy needs in 1989.

Improvements in energy use in the pulp and paper industry from 1978 to 1989 were generally the result of high rates of capacity utilization (in 1989 relative to 1978), greater application of heat recovery technologies, increased use of the thermo-mechanical pulping (TMP) process and better energy

management. Between 1975 and 1984 (the last year for which public information is available), total Canadian TMP capacity grew from 620 to 12,275 air-dry tonnes per day. This represented 34 percent of mechanical pulping capacity and 15 percent of the total pulping capacity in Canada in 1984.

Another factor which contributed to improved energy intensity in the pulp and paper industry was the increase in the market share of electricity from 19 percent in 1978 to 23 percent in 1989. This was mainly the result of increased penetration of the TMP process and of the success of Hydro-Québec's surplus program aimed at the industrial sector. This program increased electricity's share over and above that resulting from the adoption of the TMP process. However, the increasing use of internally generated fuels, which are less expensive to the industry but are considerably less efficient than purchased fuels, the decline in the industry output, and fuel consumption data not reported in earlier years more than offset the impact of these improvements on measured energy intensity. As a result, total input energy intensity in the pulp and paper industry shows little improvement from 1978 to 1989.

In the **pulp and paper** industry we expect measured energy intensity to be 18 percent lower in 2010 than it was in 1989, in light of the following anticipated developments:

- continued penetration of TMP, leading to total energy efficiency improvements of about 4 percent over the projection period;

- a shift towards newsprint production from 20 percent of the industry's output currently to 25 percent by 2010; newsprint production requires 40 percent less energy than kraft pulp production, as newsprint relies less on wood wastes;

- increased use of recycled fibre in newsprint and other paper production leading to energy efficiency improvements of about 5 percent;

- additional improvements in energy efficiency of 7 percent by 2010 resulting from better energy management, use of heat recovery methods, use of more efficient electric motors, cogeneration and more general productivity improvement.

Canadian **steel** production in 1989 was lower than in 1979, when it was at an historical peak. However, energy use per unit of output declined by 6 percent between 1979 and 1989; this decrease occurred despite lower capacity utilization which would normally cause energy intensity to rise. Energy savings were the result of better energy management, a greater proportion of steel produced using the continuous casting production process and in electric furnaces, and increased productivity following large investments in new equipment, greater automation and computerization.

From 1978 to 1989, the share of steel produced using the continuous casting process increased from 20 to 49 percent. This has led to productivity improvements of some 20 percent as the continuous casting process reduces waste of materials and energy.

The penetration of electric arc furnaces paralleled that of the continuous casting process, the share of steel produced using the electric arc furnace increased from 22 percent in 1978 to 31 percent in 1989. As in the pulp and paper industry, increased use of electricity in steel production led to improvements in measured intensity.

We expect energy intensity improvements in **iron and steel** production of about 12 percent by 2010. These will result largely from:

- an increased share of mini-mills output in steel production (mini-mills use electric furnaces and ferrous scrap to produce steel. Steel produced from scrap uses less than half the energy of steel produced from ore);

- increased use of ferrous scrap in basic oxygen furnaces;

- replacement of smaller less efficient plants with optimum sized plants using the latest equipment;

- installation of advanced equipment to recover waste heat for pre-heating materials used for making steel and primary iron; and

- more efficient mixing of fuel and oxygen in basic oxygen furnaces (the Lance Bubbling Equilibrium system) and direct smelting technologies. The Lance Bubbling Equilibrium System preheats the charge, which results in higher yields, increases the amount of scrap which can be charged and improves the quality of the steel. Direct smelting technologies use more coal relative to coke in the production of iron. This process saves the energy otherwise lost in the conversion of coal to coke.

The **smelting and refining** industry consists of the aluminium industry and a large number of plants involved in the smelting and refining of such metals as copper, nickel, lead, zinc, gold and titanium. The aluminium industry is by far the largest energy consumer in this sub-sector. It accounted for an estimated 85 percent of the total smelting and refining energy demand in 1989.

In smelting and refining, energy intensity declined by 13.9 percent over the 1978 to 1989 period. Energy savings were largely the result of:

- better energy management;
- greater use of more efficient fuels (the share of electricity increased from 62 percent in 1978 to 71 percent in 1989);
- relatively high capacity utilization, particularly in the aluminium industry; and
- a greater application of newer and more energy efficient technologies and processes such as automation and computerization.

For the **aluminium** industry, we expect that the most up-to-date aluminium smelting technologies presently used in Becancour, Quebec will be adopted by all new plants. We expect that this will lead to a decline in energy intensity of about 9 percent from 1989 to 2010, as this process is more efficient than older processes, and as certain existing aluminium smelters will be replaced over the projection period.

Smelting and refining other than aluminium is assumed to experience the same rate of decline in energy intensity as assumed for aluminium smelting as these smelting techniques are broadly similar to that for aluminium, and as some consolidation of smaller less efficient units is expected.

Cement production is based on two processes, referred to as the wet process and the dry process. The dry process uses about twenty percent less energy per unit of output than the wet process. In the wet process the materials used must be dried prior to distribution for use, while in the dry process this stage is not required. Currently about 82 percent of cement production is based on the dry process, a substantial increase over 1978 when 65 percent of the cement was produced in this way. However, use of these processes varies across regions. In 1989, in the Atlantic region and Saskatchewan, all cement was produced using the more efficient dry process. In Manitoba, on the other hand, all cement was produced using the wet process. In other regions the use of the dry process dominated, accounting for 65 to 85 percent of cement production.

Although the cement industry pursued its shift towards the dry process throughout the 1979 to 1989 period, published data shows an increase in energy intensity of some 7 percent over this period. Capacity utilization in the cement industry was at about the same level in 1989 as in 1978. However, over this period coal and petroleum coke use increased significantly at the expense of heavy fuel oil and natural gas. Both coal and petroleum coke are economical to use in cement manufacturing but have lower utilization efficiency. This contributed to the increase in the industry energy intensity. Further, the cement industry also moved towards the use of refuse-derived fuels such as old tires in Ontario and biogas in B.C. In general, these fuels, while cheaper, are less energy efficient and their use tends to increase energy intensity.

In the **cement** industry we expect a reduction in energy intensity of about 6 percent by 2010. We have assumed that:

- all cement will be produced using the dry process;
- mainly recovered waste heat will be used to pre-dry raw materials;
- secondary cementing materials will be used more extensively. Traditional cementing materials must be heated to high temperatures before they can be ground for use in cement manufacturing, while secondary materials such as fly ash and blast furnace slag (by-products of other industrial processes) do not require this stage; and
- pre-heating at the clinker burning stage will be more widespread.

Savings in energy use in the rest of the industrial sector is expected to result from:

- increased use of efficient electric motors;
- application of advanced heat recovery technologies; and
- better energy management.

In addition to the industry-specific observations noted above, the industrial sector's demand for energy in the projection period will be determined by the growth in industrial output, absolute and rela-

tive energy prices, shifts in output among industries within the industrial sector and trends in productivity and investment. Utility-sponsored demand management programs such as those by Ontario Hydro, B.C. Hydro and Hydro-Québec will also have some influence on demand. We expect industrial electricity demand in 2010 to be 1029 petajoules with demand management, compared to 1051 petajoules without it.

The share of energy-intensive industries in the industrial sector can have a major impact on energy use and energy intensity of the sector as a whole. In the Control Case industrial output is projected to grow at an average annual rate of 2.1 percent over the projection period (Table 4-6), while growth of the major energy intensive industries is 1.8 percent per year. Thus, in our projection, the share of these industries declines moderately throughout the projection period from 32 percent in 1989 to below 28 percent in 2010. We estimate that if the energy intensive industries were to maintain their 1989 share of output to the year 2010, industrial energy demand would be about nine percent higher than we have projected.

Our analysis based on the foregoing developments results in average annual increases in total industrial energy demand of about 2 percent over the projection period. Industrial energy intensity is projected to decline by about 0.7 percent per year from 1989 to 2010. Fuels used for bitumen production have a major impact on the measured energy intensity. If fuel requirements for bitumen production are excluded, the rate of decline in energy intensity is 1.0 percent per year, and the increase in total energy demand is 1.8 percent per year.

Over the projection period, savings in energy use per unit of output will come largely from the replacement of existing equipment by more efficient capital stock, widespread technological changes, and, to a lesser extent, from a shift in output toward less energy intensive industries and a shift to more energy efficient fuels, in particular electricity.

The share of coal in industrial energy use (Table 4-7) shows a marked increase, largely because of its projected use in bitumen production, as natural gas becomes progressively more expensive than coal (see Chapter 7). The electricity *share* between 1989 and 2010 shows little change as a result of the strong growth in coal and natural gas use in bitumen production and, to a lesser extent, demand management programs implemented by electrical utilities. Hog fuel and pulping liquor shares are projected to decline due to an anticipated increase in the use of TMP and CTMP technologies in the pulp and paper industry.

We expect considerable improvement in the competitive position of heavy fuel oil versus natural gas. As discussed above in Section 4.2.1 we have not assumed any differentiation of natural gas prices across consuming sectors. As a result the natural gas price to industrial users rises to exceed the price of heavy fuel oil in the eastern part of the country. We expect there to be no deterioration in the share of natural gas for industrial use as the price of natural gas approaches parity with heavy fuel oil. As the ratio moves from parity to 110 percent we expect that new industrial consumers will choose heavy fuel oil over natural gas. Based on recent experience in the Quebec market, and discussions with industry, we expect there to be no loss of existing natural gas markets with a premium of up to ten percent for the natural gas price, relative to heavy fuel oil. Once the premium exceeds ten percent, however, we expect gas to lose market share to heavy fuel oil, as it becomes economic to switch fuels. There are certain specific industrial processes for which only natural gas can be used, but these are not a large share of the market.

Table 4-6

Industrial Energy Demand

Average Annual Growth Rates (Percent)

	1973-1980	1985-1989	1989-2000	2000-2010	1989-2010
End Use Demand	n/a	2.9	1.8	1.9	1.9
Real GDP[a]	-0.7	4.0	2.5	2.8	2.6
Real Energy Price[b]	4.3	-4.1	2.9	1.4	2.1
Intensity[c]	n/a	-1.0	-0.7	-0.9	-0.7

Notes: [a] 1981 Dollars.
[b] The energy price is an index of fuel prices for the sector.
[c] Megajoules per $C 1981.
n/a: Not available due to discontinuities in data.

Table 4-7

Industrial Energy Demand

	1973	1980	1989	1995	2000	2005	2010
				Levels			
End Use Demand[a]	2084.8	2399.4	2628.9	2950.3	3207.6	3524.8	3868.2
Real GDP[b]	109.9	104.6	137.3	159.2	179.9	205.1	236.4
Real Energy Prices[c]	0.7	0.9	1.0	1.3	1.4	1.4	1.6
Intensity[d]	19.0	22.9	19.2	18.5	17.8	17.2	16.4
				Input Market Shares (percent)			
Coal	2.0	1.8	2.0	1.9	1.9	4.3	6.2
Coke and Coke Oven Gas	9.9	8.5	6.9	7.4	7.2	6.9	6.6
Electricity	20.0	21.0	25.2	26.0	26.4	26.4	26.5
Heavy Fuel Oil	16.0	13.4	6.5	6.5	7.5	9.5	13.0
Natural Gas	26.9	29.8	35.9	36.2	36.0	33.0	28.9
Hog Fuel and Pulping Liquor	13.8	14.9	15.6	14.2	13.1	12.0	11.1
Petroleum Coke	0.0	0.2	1.5	1.6	1.7	1.8	1.8
Other Fuels	11.4	10.4	6.3	6.1	6.0	6.0	5.8
Total Market Shares	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Notes: [a] Petajoules.
[b] Billions of 1981 Dollars.
[c] The energy price is an index of fuel prices for the sector.
[d] Megajoules per $C 1981.

Our projection shows the natural gas price relative to heavy fuel oil in 2010 to be 35 percent higher in Quebec, 23 percent higher in Ontario, and 16 percent higher in British Columbia. As a result, natural gas demand in Quebec in 2010 is projected to be 27 percent below 1989 levels, while in Ontario it is at about the same level as in 1989. In British Columbia, we have included the Vancouver Island natural gas pipeline. Thus, while natural gas loses share from the mid-1990s to 2010, industrial gas demand is still 16 percent above 1989 levels in 2010, as a result of this new market. For Canada as a whole, the natural gas share of industrial energy demand (including fuel for bitumen) declines from almost 36 percent in 1989 to just under 30 percent in 2010.

A number of uncertainties surround the industrial energy demand projection. Among the most important are:

- the rate of adoption of new production processes which affect energy demand, e.g. the dry process displacing the wet process in cement manufacturing, direct smelting technology in primary iron production, and Lance Bubbling Equilibrium in steel-making;
- the rate of adoption of energy-saving techniques, e.g. waste heat recovery methods;
- shifts in the distribution of output between energy intensive and less energy intensive industries;
- the impact of major technological developments, such as the increased use of energy efficient electrical motors and the development and application of super-conductivity;
- trends in productivity and the rate of investment; and

- environmental issues, such as the increased recycling of waste materials (e.g. aluminium cans, ferrous scrap, used newspaper and other types of paper).

There also exists uncertainty about the levels and relative prices of fuels to the industrial sector, and the resulting fuel shares. This would have the most direct impact on the shares of natural gas and heavy fuel oil.

The results of our industrial energy demand projections should be viewed with these uncertainties in mind.

As compared to the 1988 Report, the outlook for the industrial sector resembles more closely the Low Case than the High, as economic growth in the Control Case is closer to the Low than the High Case. In the Control Case industrial energy demand grows at 1.9 percent between 1989 and 2005, as compared to 1.7 percent in the 1988 Low Case and 2.8 percent in the High Case. In the Control Case and in both cases in the 1988 Report, industrial energy intensity declines at about 0.7 percent per year from 1989 to 2005. The electricity share is comparable in 2005 across the Control and two cases of the 1988 Report, at just over 26 percent. Given our price relatives for natural gas and heavy fuel oil, the oil share in the Control Case in 2005 is about 15 percent, compared to close to 10 percent in the 1988 Report. The higher oil demand is at the expense of natural gas, whose share is 33 percent in 2005 in the Control Case, compared to 36 percent in the 1988 Report cases. As well the share for coal and coke is lower in the Control Case than in the 1988 Report, due to lower coal use for bitumen production.

4.2.5 Non-Energy Hydrocarbon Use

This section discusses hydrocarbons used for non-energy end use purposes, such as petrochemical feedstocks, asphalt, lubes and greases. Non-energy hydrocarbon use in Canada amounted to 667 petajoules in 1989, or about 8.7 percent of total end use demand (Table 4-8). This included over 443 petajoules for petrochemical feedstocks, 129 petajoules for asphalt and 94 petajoules for the

Table 4-8

Non - Energy Uses

(Petajoules)

	1973	1985	1989	1995	2000	2005	2010
Petrochemicals							
Natural Gas	41	175	172	183	196	211	227
Oil	82	134	120	133	145	158	173
NGL	0	96	151	211	235	242	250
Total Petrochemicals	122	405	443	526	576	611	650
Asphalt	138	120	129	149	164	181	201
Other Non - Energy Uses	102	82	94	106	117	129	143
Total Non-Energy	**362**	**607**	**667**	**781**	**856**	**921**	**994**

Note: The numbers on this table have been rounded.

production of lubricants, greases, petroleum coke and other non-energy petroleum products. Historical and projection period data are presented in Table 4-8.

Primary petrochemicals are divided into four groups:

- olefins (ethylene, propylene, butadiene and butylene);
- aromatics (benzene, toluene and xylene);
- methanol; and
- ammonia.

Currently light oil fractions (such as naphtha), natural gas and natural gas liquids (propane, butane and ethane) are the favoured feedstocks for production of primary petrochemicals, which are, in turn, important inputs for producing products for a number of industries including agriculture, plastics, cosmetics, textiles, transportation equipment, rubber and forest products. The wide range of uses for petrochemicals means that the outlook for the industry is closely tied to the growth prospects for the economy as a whole. However, since much of our petrochemical production is exported to the U.S., South Korea and elsewhere, prospects for the Canadian industry also depend on world economic growth and Canada's competitive position in supplying such products.

Projections of petrochemical feedstock demand therefore depend on several uncertain factors:

- Canada's competitive position in the world petrochemical market, which is affected by relative feedstock costs, capital and operating costs, transportation costs and access to markets;

- the timing and construction of new Canadian plants during the projection period, which is affected by the world-wide scheduling of plant capacity, and by the growth in product demand; and

- product slate requirements and, for those plants with feedstock flexibility, prices of alternative feedstocks.

The relatively long (four to five year) time period required for the planning and construction of new plants, combined with the variability of both feedstock prices and product demand, has resulted in cycles of strong demand and high capacity utilization alternating with periods of depressed product market conditions and large capacity surpluses during which producers have not always recovered their operating costs. This is a global problem, affecting the industry in Canada and other countries. To operate efficiently and minimize production costs per unit of product, plants must run at close to full capacity.

In recent years, the bulk of the growth in primary petrochemical production has been in Alberta, where natural gas and ethane are relatively cheaper because of low transportation costs. The industry in Quebec and Ontario, which is largely naphtha-based, has invested heavily in an effort to increase capacity and flexibility in the mix of feedstocks which can be used.

The outlook for ethylene depends on the future performance of the major ethylene derivatives: polyethylene, polystyrene and polyvinyl chloride. Canadian production must compete in a highly competitive world market for these products. Over the eighties world-wide demand for these derivatives rose by over 4 percent per year. Industry opinion suggests that, over the long term, world demand for ethylene derivatives will continue to grow strongly. In Canada the bulk of the growth in ethylene production is expected to be in Alberta, where projected increases in natural gas production should ensure plentiful supplies of ethane (see Chapter 8). Dow Chemical has already announced plans to build a 550 kilotonne ethylene plant at Fort Saskatchewan, Alberta in 1995, requiring about 35 petajoules of ethane feedstock per year. A further expansion of the Dow plant - slated for about 1997 - is expected to require an additional 18 petajoules of ethane feedstock.

Anticipated capacity additions in Ontario and Quebec are expected to lead to growth in production of ethylene and aromatics of about 2.5 percent per year throughout the projection period. However, growth in the use of oil as a petrochemical feedstock is expected to be somewhat slower as oil-based products - particularly naphtha - should provide greater returns as an input to higher-priced gasoline. Thus, oil demand for petrochemical production is expected to rise by only 2 percent per year to 157 petajoules by 2010. It is expected that an ample availability of liquefied petroleum gases (LPGs) - propane and butanes - in Ontario will encourage their increased use in the production of ethylene while heavier feeds - naphtha and gasoil - will go to the production of the aromatics and gasoline. Petrochemical feedstock demand for propane and butanes is projected to rise by about 3 percent per year to 43 petajoules by 2010. If the relevant authorities were to allow the Soligaz project to proceed, further increases in consumption of NGLs in petrochemical production would occur with, perhaps, an expansion in ethy-

lene capacity for Quebec. For those petrochemical plants with feedstock flexibility, it is extremely difficult to project the specific mix of feedstocks with any degree of certainty. This flexibility allows plant operators to make day to day decisions concerning the most economic feedstock mix to produce a desired product slate.

An area of opportunity for the petrochemical industry is in octane enhancement for gasoline. The phase-out of lead in this role presents an opportunity for toluene and methyl tertiary butyl ether (MTBE). Neste Oy and Petro-Canada are joint owners of a new MTBE plant scheduled to come on stream in 1991. The plant, located in Edmonton, will produce about 530 kilotonnes of MTBE per year and require about 19 petajoules of butane for feedstock.

Methanol production is projected to grow at about the same rate as the total economy. Because North American capacity is under-utilized we do not include any major new methanol plants in this outlook. However, upgrades and minor expansions should keep natural gas demand for methanol production rising by about 2 percent per year over the projection period. A major uncertainty here is that government policy in Canada and the U.S. may provide incentives for increased methanol use in the transportation sector, which could in turn encourage substantial capacity additions in Alberta and British Columbia.

Ammonia is used primarily for fertilizer production for the agricultural sector and is not expected to see much demand growth over the projection period as world-wide capacity remains under-utilized. In 1992, the 100 kilotonne Saferco ammonia plant in Belle Plaine, Saskatchewan is slated to begin production. It is expected to require about 14 petajoules of natural gas as feedstock and is the only new plant included in this outlook. Although some Canadian ammonia plants have shut down in recent years, we do not project any further closures.

Total petrochemical feedstock demand is expected to grow by 1.8 percent per year from 1989 to 2010. Most of this growth is in demand for natural gas liquids which increases at 2.4 percent per year. Petrochemical feedstock demand reaches 650 petajoules in 2010, as compared to 443 petajoules in 1989 (see Table 4-8).

Asphalt is the most important non-energy hydrocarbon use other than petrochemical industry requirements. Asphalt is used primarily for surface pavement of roads and airport runways. It is also used for roofing; lining canals, reservoirs, dams and dikes; binding rocks in breakwaters; insulating underground waterpipes and communication cables; and railroad beddings. Trends in the extent of road paving will have a major influence on total asphalt demand, as paving accounts for some 75 percent of total asphalt use.

Over the projection period, although demand for asphalt is largely determined by economic activity, it will continue to be influenced by increased use of recycled asphalt for road paving. Thus we project demand for asphalt to grow at an average annual rate of 2.1 percent, slightly below the rate of overall economic growth.

Lubricating oils and greases, petroleum coke and non-petroleum products account for 14 percent of non-energy demand. We project the demand for these products taken together to grow at average annual rates of about 2 percent. By 2010 these products would still account for 14 percent of non-energy demand.

Non-energy demand is projected to grow at 1.9 percent per year in the Control Case, from 1989 to 2010. Over the period 1989 to 2005 the average annual growth is 2.0 percent. This compares to about 1.7 percent in the 1988 Report High and Low cases. The major difference between the Control Case and the 1988 Report is a slightly different mix of petrochemical feedstocks, with greater demand for natural gas and natural gas liquids in the Control Case, and lower demand for oil than in the 1988 Report.

4.2.6 Transportation Sector

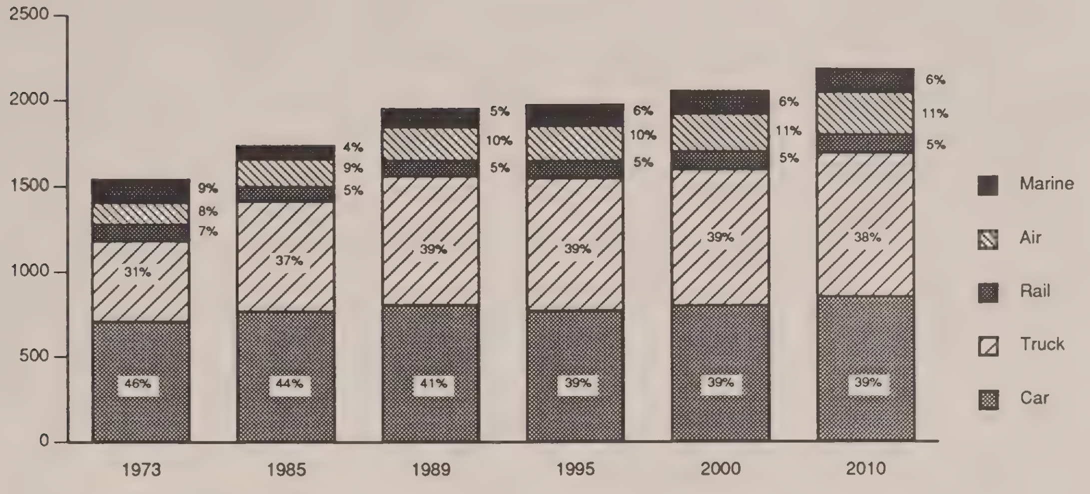
The transportation sector accounted for over 25 percent of total end use energy demand in 1989, second only to the industrial sector. This sector, which includes road, air, rail and marine demand, is the largest consumer of refined petroleum products, accounting for over 64 percent of the total end use petroleum product demand.

In 1989, the road sector accounted for 80 percent of transportation energy demand followed by air (9.8 percent), rail (5.5 percent) and marine (4.7 percent) (see Table 4-9 and Figure 4-6). Petroleum products account for over 98 percent of transportation energy use, with propane, natural gas and electricity making up the balance. Although motor gasoline's share of transportation fuel has declined from its 1975 peak of 73 percent, it is still the most important fuel, accounting for 62 percent of transportation fuel use in 1989. Over the same period, the share of diesel fuel increased from 13 to 24 percent as truck diesel use more than doubled.

Figure 4-6

Distribution of Transportation Demand by Sector

(Petajoules)



Source: Appendix Table A10-1.

Table 4-9

Transportation Energy Demand

(Petajoules)

	1973	1985	1989	1995	2000	2005	2010
Road	1181	1414	1560	1546	1597	1647	1694
Gasoline	1106	1134	1206	1165	1190	1214	1236
Diesel	75	263	322	340	359	376	392
Other	0	17	32	41	49	57	66
Air	126	160	192	203	217	228	244
Rail	101	85	91	100	105	106	109
Marine	132	74	107	125	131	133	137
Total	**1541**	**1734**	**1950**	**1973**	**2050**	**2114**	**2184**
Fuel Efficiencies							
Total Car Stock (L/100KM)	16.73	12.80	10.89	9.68	9.23	8.86	8.52
Small Cars	12.99	10.30	9.40	8.75	8.41	8.10	7.80
Large Cars	19.92	15.89	13.11	11.24	10.69	10.28	9.89
Total Truck Stock (L/100KM)	28.56	23.66	20.31	18.33	17.47	16.80	16.17
Average Energy Use							
Per Car (GJ)	94	73	68	60	58	55	53
Per Truck (GJ)	258	209	191	166	156	148	142

Note: Numbers on this table have been rounded.

The evolution of energy use in the transportation sector in Canada since the 1960s can be divided into four phases:

- The 1965 to 1973 period was one of relatively inexpensive energy and strong economic activity. Car and truck stock increased at an average of 5 percent per year. Motor gasoline and road diesel demand grew at six and 15 percent per year, while total road demand increased at an average of 6 percent per year. Energy use for aviation grew at 10 percent on average, while rail and marine demand experienced modest growth of 1.3 and 2.5 percent, respectively. Total transportation energy demand grew at 6 percent per year, on average.

- The 1973 to 1980 period was characterized by slower economic growth and rising energy prices. The car stock growth averaged 4 percent per year while the truck stock grew at 7 percent annually. Despite this growth in car and truck stock, significant fuel efficiency gains and an increase in the small car share of new car sales (to 56 percent in 1980), were the major factors limiting growth in motor gasoline demand to less then 3 percent per year. Diesel demand increased at close to 16 percent per year, as a result of truck stock growth, a shift in the mix of stock to diesel trucks, increased distance driven and less rapid fuel efficiency gains than in the car sector. Over this period, air sector energy use grew at 4.5 percent, and marine at 2 percent annually, while rail sector energy demand declined by one percent per year. Total transportation energy use increased annually by 3.5 percent.

- The 1980 to 1983 period was one of declining transportation energy use, due to both the economic slowdown and sustained increases in energy prices. Car stock fuel efficiency improved by 4 percent per year partly as a result of a strong increase in the share of small cars. Car and truck stock growth averaged 1.4 and 0.4 percent per year, respectively, down from the much higher rates of the 1970s. Road energy demand declined by 5 percent per year and for the first time, motor gasoline and road diesel demand fell, by an average of 5 and 0.7 percent per year. Air, rail and marine energy use declined by 5.3, 5.6, and 16 percent per year, respectively. Total transportation energy use fell at a rate of 5 percent per year.

- The 1983 to 1989 period was one of strong economic growth and continued, though slowing, fuel efficiency improvements. Car and truck stocks increased at an average rate of 2.6 and 2.9 percent per year, respectively. Road transportation energy demand increased at an average of 2.3 percent per year. Motor gasoline demand increased marginally (by less than one percent per year), but this was more than offset by increases of more than 8 percent annually in road diesel demand. Air, rail and marine energy grew at 4.6, 2.4, and 3 percent respectively. Total transportation energy requirements rose at 2.5 percent on average, over this period.

Our projections of road, air, rail and marine demand are discussed, in turn, in the following sections.

Road Sector

Within the **road sector**, cars and trucks each account for roughly half of the energy used. Car energy demand consists almost entirely of motor gasoline, while truck energy demand is split between motor gasoline (54 percent), diesel (42 percent) and other fuels (4 percent), mainly propane (see Table 4-9).

Growth in road transportation energy demand is approximately equal to the sum of the growth rates of the stock of vehicles, of the average fuel efficiency of the stock and of the average distance driven per vehicle.

- Car and truck stock growth are determined mainly by real personal disposable income (cars), real gross domestic product (trucks), operating costs and financing charges and demographics.

- Average car and truck stock fuel efficiencies depend on new vehicle fuel efficiency improvements and stock turnover. Stock fuel efficiency is also influenced by shifts between weight classes, shifts between large and small cars, and shifts between cars and minivans and other special vehicles not normally defined as part of the car stock. Truck fuel efficiency varies by weight class, from small light duty trucks to extra-heavy diesel trucks. The weight mix of trucks depends on commercial activity and freight transport growth, and labour, fuel and equipment costs. The main objective of freight transport is to maximize payload[1] efficiency, rather than fuel efficiency.

- The average distance driven by personal vehicles depends upon income, fuel type, fuel prices, the average age of the vehicle stock and the number of vehicles per household. Average distance driven by commercial vehicles, in particular trucks, depends on economic activity, on the truck category, on fuel type and fuel prices.

In our Control Case, motor gasoline and diesel prices grow at approximately one percent per year in real terms. This reflects our oil price projection, and an assumption that refinery margins for petroleum products are constant in real terms throughout the projection period. The number of households increases at 1.5 percent annually, while real personal disposable income shows relatively little growth during the 1990s, but rebounds to grow at one percent annually from 2000 to 2010. Real gross domestic product, the main factor influencing commercial transportation, grows at 2.3 percent per year from 1989 to 2010.

The basis for our projections of stock growth, average fuel efficiencies and average distance driven are discussed below, first for cars and then for trucks.

Cars

In the Control Case, new car sales increase by 1.8 percent per year, resulting in growth of the **car stock** of 1.5 percent annually between 1989 and 2010. The definition of cars for personal use excludes vans, four-by-fours, and light trucks purchased for personal, rather than commercial purposes. It is difficult to establish from available data the size of this latter category (it is currently included in the definition of `light trucks'). However, preliminary estimates suggest that if vehicles of this kind purchased for personal use were included in the car definition, reported car sales would be somewhat higher in the early 1980s (when vans and light trucks began to be purchased for personal use) and as much as 24 percent higher in 1990. We expect that the penetration of these vehicles for personal use will slow down, as much of the van penetration has been a substitution for large family vehicles, such as station wagons. However, in examining the growth of car stock over the projection period, it is important to keep in mind the narrow definition of cars we have been required to use.

Another important consideration in determining car stock growth is demography. In 1973 there were on average almost 3.5 persons per household in Canada. By 1990, this figure had declined to 2.8 and, given demographic trends, we expect it to decline further to 2.5 people per household by 2010. Our projection shows car stock (as conventionally defined) growing from about 1.26 cars per household in 1990 to 1.30 cars per household in the year 2010.[2] (In the 1988 Report we reached 1.30-1.35 cars per household by 2005.) If the car stock were grossed up to reflect the sales of other vehicles for personal use, "car stock" would be about 25 percent higher, as would this ratio.

New car fuel efficiency is projected to improve by 15.5 percent or 0.8 percent annually over the 1989-2010 period (see Table 4-10). Since new cars replace less efficient vehicles in the stock, car stock fuel efficiency improves at 1.2 percent annually on average. To achieve these gains, we consider only those technologies already in the implementation phase (such as 4 speed automatic and 5 speed manual overdrive transmissions) and assume market penetration of such fully proven and/or cost-effective technologies gradually over the projection period. Technological fuel efficiency improvements are divided into two categories, body/drivetrain upgrades and engine-related upgrades:

- Body/drivetrain upgrades include improved transmissions, weight reduction and drag coefficient reduction, as well as improvements to tires,

1 Payload refers to the cargo from which revenue is derived, that is the goods shipped by the truck.

2 If we consider other indicators of the make-up of the population, in determining who will buy and drive personal vehicles, in the year 2010 in the Control Case we anticipate that there will be 1.08 cars per person employed, 0.5 cars per person, and 0.94 cars per person in the labour force.

accessories and lubricants. Overdrive transmission is already widely in use: in 1987 over 60 percent of new cars sold had overdrive transmissions (4 speed automatic and 5 speed manual). We project full penetration of overdrive transmission in this outlook. Although advance overdrive transmissions (5 speed automatic and 6 speed manual) and continuously variable transmission are proven technologies, their costs will likely limit their penetration to high performance and luxury cars. The first phase of weight reduction, which occurred in the late 1970s and through the 1980s, was one of downsizing and a shift toward front wheel drive vehicles. Weight reduction has now entered its second phase, oriented toward material substitution. We assume significant use of lighter materials such as high strength steel, aluminium and plastic to replace heavier materials such as carbon steel and iron. Further, to optimize such weight reduction benefits we assume engine size and axle ratio recalibration. Drag coefficient reduction is assumed to have a significant impact on highway driving fuel efficiency and a marginal impact on city driving fuel efficiency. Reduction of the drag coefficient will, however, be limited by consumers' requirements for usable space and comfort. Any fuel efficiency gains from improved tires, accessories and lubricants are assumed to be limited; among these only the use of advanced synthetic lubricants is presently considered cost-effective. We expect market penetration of low profile radials to be limited to high performance vehicles.

- Engine upgrades are gradual and can result in improved fuel efficiency or increased performance; the two major categories of engine upgrade include improvement to spark ignition engines and increased electronic controls. During the first half of the 1980s the focus was on increasing specific output (horsepower per cubic centimetre) and on a reduction in internal friction of components. In the latter half of the 1980s, a new round of friction reduction was initiated, which focussed on new low-friction piston design, low tension piston rings, and better control of piston and bore dimensions. In the 1990s, further fuel efficiency gains and performance improvements are projected from the introduction of valve control technology and multivalve engines. The increased use of microprocessors during the last decade improved fuel efficiency and performance and reduced exhaust emissions and maintenance. We project full implementation of technologies such as knock-limiters, deceleration fuel shutoff and electronic transmission control, but limited market penetration of less cost-effective technologies such as multi-point fuel injection. Although these technological improvements will result in significant fuel efficiency gains, they could be partly offset by an increasing share of urban driving and congestion (discussed below).

Average distance driven by cars is projected to stay relatively constant, consistent with the assumption that for long distance travel, people will prefer other modes of transportation such as air travel. It is also consistent with our projection that the real motor gasoline price will increase at almost twice the rate of real disposable income per household.

In **summary**, for the car sector of road transport, we expect motor gasoline use to increase at 0.2 percent per year over the projection period, as car stock increases by 1.5 percent annually, car stock fuel efficiencies improve by 1.2 percent annually and the average distance driven remains constant. Car energy demand increases at a slightly higher rate of 0.3 percent annually as alternative fuels gain a small share of the sector's energy use over the period.

Major **uncertainties** relating to this projection include the rate of growth and composition of the car stock, and the pattern of fuel efficiency improvements over time. However, there are other factors relating to car use which are equally important. Car fuel efficiency ratings reflect test results, while the actual efficiency achieved on the road may be considerably less. Although we adjust the rated efficiencies in our database and projection to conform more closely to those expected under actual driving conditions, there are several areas of uncertainty when projecting these adjustments into the future. Performance reflects, among other things, the amount of city and highway driving, city driving being less efficient. As the number of vehicles increases in the future, as urban congestion increases the length of time for a specific trip, as idling time increases, and as urban driving accounts for a larger share of total distance driven, the difference between rated and actual fuel efficiencies will increase. This impact could be quite large; one estimate suggests that car gaso-

line demand could be increased by as much as 20 percent by the year 2010[1] relative to the gasoline demand projected when standard values are used to adjust from rated to actual fuel efficiency.

Trucks

In the Control Case total new truck sales and **truck stock** are projected to increase by an average of one and two percent per year, respectively (0.9 and 1.8 percent for motor gasoline trucks, and 2.4 and 3.1 percent for diesel trucks). The growth of the stock exceeds that of sales as a result of the slowing retirement pattern of vehicles from the stock, relative to sales. This is due to a very rapid increase in the mid-1980s which has resulted in a relatively new truck stock.

Light Duty Trucks

The light duty truck market consists of pick-ups, vans (full size and mini), light duty four-by-fours and special purpose vehicles.

1 Westbrook, F. and P. Patterson, "Changing Driving Patterns and Their Effect on Fuel Economy" presented May 2, 1989 at the SAE Government/Industry Meeting, Washington, D.C.

Table 4-10

Determinants of Motor Gasoline Use

Average Annual Growth Rates (Percent)

	1973-1980	1980-1985	1985-1989	1989-2000	2000-2010	1989-2010
Car Sector						
Real Gasoline Price ($81/GJ)	2.1	7.9	5.7	1.6	0.4	1.0
New Car Sales						
Small	0.7	5.9	-2.9	2.5	1.6	2.1
Large	-2.1	1.4	-4.4	1.4	1.0	1.2
Total	-0.6	4.1	-3.5	2.1	1.4	1.8
Car Stock						
Small	4.4	4.4	5.3	2.2	1.8	2.0
Large	3.3	-1.5	0.3	0.1	1.0	0.6
Total	3.8	1.5	3.1	1.4	1.5	1.5
New Car Fuel Efficiency (L/100KM)						
Small	-2.7	-4.2	0.5	-0.8	-0.8	-0.8
Large	-4.5	-6.2	-1.5	-0.6	-0.8	-0.7
Total	-4.0	-5.5	-0.5	-0.8	-0.8	-0.8
Car Stock Fuel Efficiency (L/100KM)						
Small	-0.8	-3.4	-2.3	-1.0	-0.7	-0.9
Large	-0.4	-3.9	-4.7	-1.8	-0.8	-1.3
Total	-0.6	-4.4	-4.0	-1.5	-0.8	-1.2
Average Distance Per Car (100KM)	-0.5	0.9	2.3	0.0	0.0	0.0
Car Gasoline Demand (PJ)	2.7	-2.0	1.3	-0.1	0.7	0.3
Truck Sector (Gasoline)						
New Truck Sales	3.6	3.5	6.2	0.7	1.1	0.9
Truck Stock	6.8	1.0	6.0	2.3	1.4	1.9
New Truck Fuel Efficiency (L/100KM)	-5.5	-5.0	1.2	-0.9	-0.8	-0.8
Truck Stock Fuel Efficiency (L/100KM)	-1.8	-4.2	-4.5	-1.5	-0.8	-1.2
Average Distance Per Truck (100KM)	-1.8	-1.3	1.7	-0.6	-0.2	-0.4
Truck Gasoline Demand (PJ)	2.9	-5.0	2.3	-0.1	0.1	0.0

Note: Numbers on this table have been rounded.

Pick-up trucks are used for business, and on farms, but also for recreational purposes. Full-size vans are often used as service vehicles, while minivans and four-wheel drive utility vehicles often substitute for large family cars. Special purpose vehicles are used to meet specific consumer requirements such as transportation for the disabled. Sales of minivans and four-wheel drive vehicles increased by 12 percent per year over the 1986-89 period and this market now represents 44 percent of new light duty truck sales. This market is soon expected to reach its full potential and as a result we anticipate lower annual growth rates in the long term than have been experienced recently. However, as a result of the increasing popularity of minivans, four-wheel drives and other light duty utilities such as recreational vehicles, the **light duty truck stock** is projected to have the strongest average growth of any truck category, at 2.1 percent per year.

The **average fuel efficiency of light duty trucks** is projected to improve by 0.8 percent per year. Most of the efficiency gains will come, with a few exceptions, from the same technological improvements discussed for cars. Minivans and most four-wheel drive vehicles sold for recreational use are in fact more efficient downsized vehicles than their full size light truck counterparts. As their share of the light truck category grows, fuel efficiency of that class of vehicles will correspondingly improve. **Distance driven** by light trucks is expected to remain fairly constant over the projection period.

Medium/Heavy and Extra Heavy Trucks

The **medium/heavy truck segment** includes both gasoline and diesel vehicles. Since the mid-1970s, the composition and size of this category has changed markedly. In the 1970s gasoline trucks were the most important component. By 1989 diesel trucks accounted for over 30 percent of the total medium/heavy stock, compared to less than 5 percent in 1975. However, at the same time as the diesel share has increased, the stock of this category of trucks has declined by 2 percent per year from 1975 to 1983 and 5.3 percent per year from 1983 to 1989. Due to its commercial nature, this segment has been and will continue to be affected mainly by the focus of industry on maximizing payload efficiency, which tends to favour the extra-heavy truck segment. Another factor has been the increasing use of diesel trucks, which relative to gasoline trucks cover about 20 percent greater distance per year, have better fuel efficiency and longer life expectancy. The share of motor gasoline in new medium/heavy truck sales declined from over 94 percent in 1975 to about one third in 1987. The decline in motor gasoline prices in real terms over the last few years has revived motor gasoline medium/heavy truck sales, although they remain below 25 percent of their 1975 level. By 2010, in our Control Case, we expect the share of motor gasoline vehicles in the medium/heavy truck stock to decline to less than 35 percent of the total, from 67 percent in 1989. Sales of medium/heavy trucks are projected to decline by 1.2 percent per year, and the **stock** declines by one percent on average. We expect a general shift to heavier, diesel trucks which results in a larger share of diesel use in the medium/heavy category, but also a trend from medium/heavy to extra heavy trucks.

Like the light duty truck segment, the **extra-heavy truck segment** has been growing rapidly, and this trend is projected to continue though at slowing rates. Sales of extra-heavy trucks have increased by an average of 8.3 and 1.8 percent per year over the 1975-80 and 1980-88 periods respectively; in 1989 with the slowdown of economic growth, sales declined by 13 percent. The extra-heavy truck stock has increased on average by 5.9 percent per year over the 1975-89 period (averaging 7.5 percent for the 1975-83 period and 3.8 percent for the 1983-89 period). Extra-heavy truck sales are projected to increase by 0.8 percent per year from 1989 to 2010, leading to stock growth of 1.5 percent over the same period. Increased competitiveness due to deregulation and the impact of the 1990/1991 recession should contribute to long-term payload efficiency maximization which, combined with increased allowable lengths of truck trailers, will slow the growth of the extra-heavy truck stock over the projection period, relative to that of the recent past.

Medium/heavy and **extra-heavy** trucks have a smaller potential for **fuel efficiency** improvements than do light trucks. While fuel efficiency is a concern, the focus is more on maximizing the payload efficiency. Given the competitiveness of the trucking industry, technologies such as slower turning high torque rise engines (replacing high speed diesel engines), improved injection systems, improved tires and advanced aerodynamics are projected to become standard features. Further fuel efficiency gains may come from on-board multi-purpose electronic systems (for example cylinder fuel injection control, speed monitoring and control or monitoring of various systems), or turbo-charged engines with intercooling.

As a result of the above factors, we assume that the **fuel efficiency of new medium/heavy and extra-heavy trucks** improves by an average of 0.6 percent per year, only 75 percent of the rate of improvement during the 1980s. We have not assumed any change in the **distance driven** by these trucks over the projection period.

For the **truck sector as a whole**, based on the above discussion of the individual truck categories, we project sales to increase at one percent per year (2.4 percent for diesel and 0.9 percent for gasoline trucks). Growth of the total truck stock is two percent (3.1 percent for diesel and 1.9 percent for gasoline). Truck stock fuel efficiency improves at the rate of 1.2 percent annually over the 1989 to 2010 period (for gasoline and diesel trucks). However, within the category of gasoline trucks, there is a shift in the mix of the stock towards light duty trucks, which are more fuel efficient than medium/heavy gasoline trucks. And in the diesel category, there is a shift towards extra heavy trucks which use more energy to cover the same distance as medium/heavy trucks, and which drive greater distances with larger pay-loads. As a result, there is no growth in truck gasoline demand, while truck diesel use increases at 0.9 percent per year. This leads to an average annual truck energy demand growth of 0.5 percent (see Tables 4-10 and 4-11).

Table 4-11

Determinants of Road Diesel Use

Average Annual Growth Rates (Percent)

	1973-1980	1980-1985	1985-1989	1989-2000	2000-2010	1989-2010
Truck Sector (Diesel)						
Real GDP Goods Producing Industries (Million $C 1981)	-0.8	2.9	3.7	2.5	2.7	2.6
Real Truck Diesel Price ($C 1981/GJ)	1.4	5.9	-0.7	1.3	0.4	0.9
New Truck Sales	6.7	2.3	3.2	2.1	2.8	2.4
Truck Stock	10.4	3.4	9.3	3.5	2.7	3.1
New Truck Fuel Efficiency (L/100KM)	-3.0	-3.4	-1.4	-1.8	-1.5	-1.7
Truck Stock Fuel Efficiency (L/100KM)	-0.9	-2.0	-2.5	-1.5	-0.9	-1.2
Average Distance per Truck (100KM)	5.5	3.4	-1.2	-0.9	-1.1	-1.0
Truck Diesel Demand(PJ)	15.4	4.8	5.3	1.0	0.7	0.9

Note: Numbers on this table have been rounded.

Road Sector Propane and Natural Gas Use

We expect limited growth for on-road propane demand as it is a relatively mature market, restricted largely to fleet vehicles. The growth of demand for compressed natural gas or NGV (natural gas for vehicles) has been limited by the lack of readily available fuelling outlets. However, we assume that with some continued incentives, a number of fleets and delivery vehicles will convert to NGV. Based on discussions with industry, the share of propane and NGV in road energy use is projected to increase from 1.9 percent in 1989 (1.7 percent for propane, and 0.2 percent for NGV) to 3.4 percent in 2010 (2.3 percent for propane, 1.1 percent for NGV).

Road Sector Summary

For the **road sector** as a whole, energy demand is expected to increase by 0.4 percent annually on average over the projection period. Truck energy demand grows by 0.5 percent and car energy demand by 0.3 percent per year. Motor gasoline use increases by only 0.1 percent per year (0.2 percent for cars and no growth for trucks) and road diesel use increases by 0.9 percent per year.

Air Sector

The **air transport sector** currently accounts for ten percent of total transportation demand for energy. Energy use for air transport increased at an average growth rate nearly twice that of GDP in the 1960s and early 1970s, mainly as a result of the growing popularity of business and vacation air travel. Passenger kilometres grew at a rate three times the growth in GDP. Since the early 1970s, however, energy use in the air sector increased at a slower rate than the growth in real GDP. This reflected slower growth in air travel and the introduction of fuel saving measures such as route rationalization, an increase in load factors and technical improvements in engine and body design.

We project energy use in the air sector to increase on average at 1.1 percent per year over the projection period, less than half the real GDP growth rate. Based on discussions with the airline industry, we project average annual growth in passenger kilometres at one-half of its historical growth for the 1975-89 period due to the impact of telecommunications on business travel and the development of intermodal services for regional travelling. We also project future aircraft fuel efficiency gains to average 1.5 percent per year as fleet renewal and specialization continue and improved air traffic procedures are implemented.

There is still uncertainty about the long-term impact on energy demand of airline deregulation. In the last few years we have seen the disappearance of some air carriers and the specialization or affiliation of others. The impact of those recent changes on the overall performance of the industry is still unknown, although it should lead to increased rationalization, and a decrease in energy use per passenger kilometre.

Marine and Rail Sectors

Marine and rail transport are used mainly for carrying bulk goods such as grains, coal, iron ore and logs, though some manufactured goods are also carried by rail. These two sectors currently account for 5.5 and 4.7 percent of transportation energy demand respectively. Consistent with recent experience, we expect energy use in these sectors to grow at a much slower rate than that of the economy. We project growth in energy use in the rail sector to average less than one percent per year, while marine energy demand should grow at slightly more than one percent per year. In the marine sector, slow renewal of fleets limits the impact of any technological fuel efficiency improvements.

The Quebec-Windsor high speed train corridor is assumed to come into service during the second half of the study period, while future fuel efficiency gains should result from the abandonment of uneconomic routes and increased load factors.

Summary

In summary, we expect transportation energy demand to grow at 0.5 percent per year on average over the period 1989-2010 (see Table 4-12). Road sector energy use increases at 0.4 percent annually (dominated by diesel demand which increases at 0.9 percent, while gasoline demand grows at only 0.1 percent per year). The major uncertainties for road sector demand relate to the size of the vehicle stock, its efficiency, and the nature of its use, in particular the degree to which congestion and urban driving offset technical improvements in vehicle fuel efficiency. Air and marine energy requirements are projected to grow at slightly more than one percent annually on average, while rail energy use grows slightly below one percent.

In the 1988 Report we had stronger growth of both gasoline and diesel use. This reflected a view that car stock growth would

Table 4-12

Transportation Energy Demand

Average Annual Growth Rates (Percent)

	1985-1989	1989-2000	2000-2010	1989-2010
Road	2.5	0.2	0.6	0.4
Gasoline	1.5	-0.1	0.4	0.1
Diesel	5.2	1.0	0.9	0.9
Other	16.9	4.0	3.0	3.5
Air	4.6	1.1	1.2	1.1
Rail	1.7	1.2	0.4	0.8
Marine	9.5	1.9	0.5	1.2
Total	**3.0**	**0.5**	**0.6**	**0.5**
Fuel Efficiencies				
Total Car Stock (L/100KM)	-4.0	-1.5	-0.8	-1.2
Small Car	-2.3	-1.0	-0.7	-0.9
Large Car	-4.7	-1.8	-0.8	-1.3
Total Truck Stock (GJ/100 KM)	-3.7	-1.4	-0.8	-1.1
Average Energy Use				
Per Car (GJ)	-1.8	-1.5	-0.9	-1.2
Per Truck (GJ)	-2.2	-1.8	-0.9	-1.4

Note: Numbers on this table have been rounded.

be higher than in this Control Case, and fuel efficiency improvements for both cars and trucks somewhat slower to be realized. However, of these two factors, it is our revised outlook for car and truck stock which constitutes the major difference between the 1988 outlooks and this projection.

4.2.7 Summary

Total end use demand by sector in the Control Case is shown in Figure 4-7. End use demand grows at 1.2 percent on average over the projection period and, by 2010 is 28 percent above 1989 levels.

The change in sectoral shares from 1989 to 2010 reflects the relative economic (and household) growth of the sectors, and the impact of energy prices and efficiency improvements on each sector's energy needs.

Slowing growth of households, moderate gains in real disposable incomes, and mandated improvements in appliance efficiency early in the projection period, all contribute to low growth in residential energy demand growth of 0.5 percent per year, and a declining share of end use energy demand over time, from almost 20 percent in 1989 to about 17 percent in 2010.

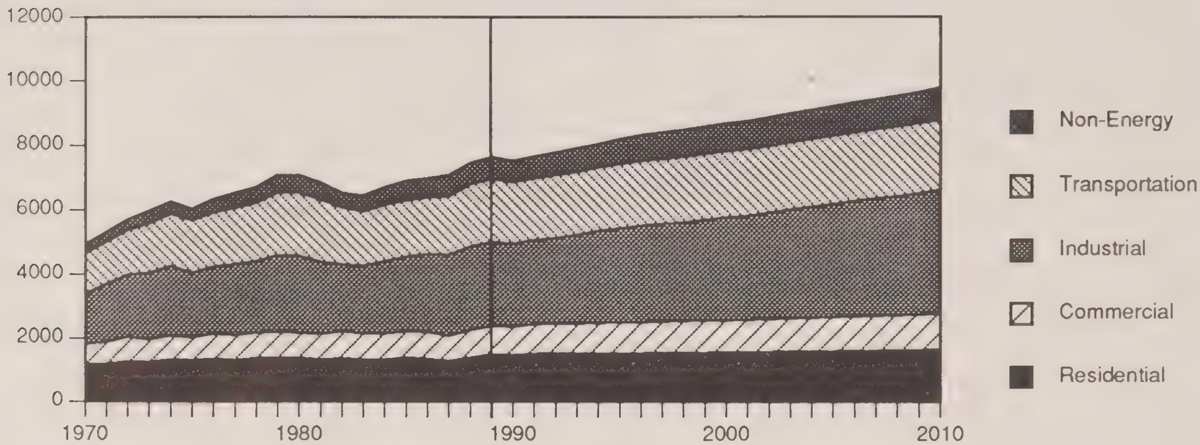
Commercial sector demand grows at one percent per year, as efficiency improvements help to offset the impact of economic growth on the sector's energy needs. By 2010 this sector accounts for 11 percent of end use demand, virtually the same share as in 1989.

Despite continued efficiency improvements, which lead to a decline in the industrial sector's energy intensity over the projection period, industrial energy demand grows at 1.9 percent per year, more rapidly than any other sector. Thus, by 2010 its share of end use demand has increased to almost 40 percent, from just under 35 percent in 1989.

Figure 4-7

Total End Use Energy Demand

(Petajoules)



Source: Appendix Table A4-3.

Slow growth in the car stock and continued improvements in both car and truck stock fuel efficiencies lead to a modest 0.5 percent annual increase in transportation energy demand over the projection period. This sector's share declines as a result, from almost 26 percent in 1989 to 22 percent by 2010.

Non-energy uses account for 10 percent of end use demand in 2010, up slightly from 9 percent in 1989.

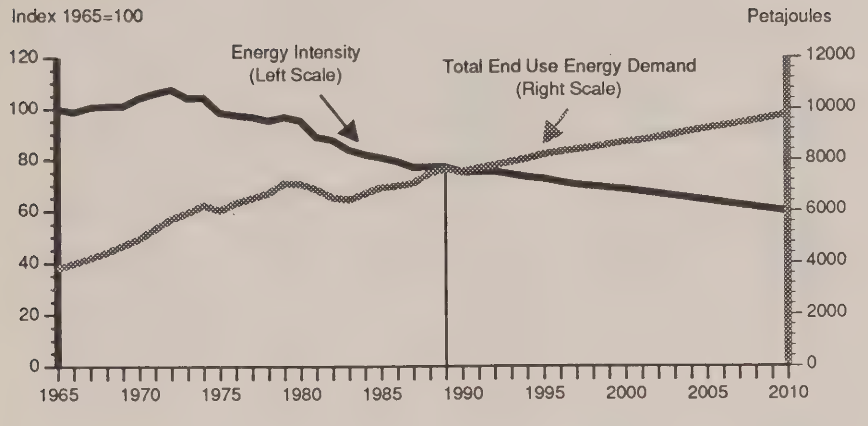
Figure 4-8 shows energy intensity over the historical and projection periods. Based on the assumptions we have made about the rate of increase of energy efficiency in specific end uses, our projection indicates that aggregate energy intensity will decline at a rate of 1.2 percent per year between 1989 and 2000, and at 1.3 percent between 2000 and 2010. While this is slower than the decline experienced from the mid-1970s to mid-1980s, it is comparable to the average decline in the latter half of the 1980s.

The inset table compares the Control Case results for 2005 with the High and Low Cases from the 1988 Report. Economic growth in the Control Case, at just over 2.2 percent from 1989 to 2005, most closely resembles the Low Case in the 1988 Report. Control Case energy prices are also closer to Low Case prices than to those in the High Case. In all sectors but residential, the level of energy demand in the Control Case in 2005 is lower than that of the 1988 High Case. The difference for the residential sector, at 3 percent, is small and reflects among other factors, a trend over the last few years to somewhat increased electricity use. Total end use energy demand in 2005 is 7 percent lower in the Control Case than in the 1988 High Case.

As compared to the 1988 Low Case, the Control Case end use demand is only slightly higher, by 2 percent, in 2005. This is consistent with the comparable pattern for economic growth and energy prices in the two outlooks. However, it should be noted that there are within each sector differences relative to the 1988 outlook, for example, the impact of mandated appliance efficiency standards on the residential sector, which are masked by this aggregate comparison.

Figure 4-8

Energy Intensity and End Use Energy Demand



Note: End use energy demand is in petajoules; Energy intensity is end use energy demand per unit of 1981$real GDP, indexed to 1965.

Differences in End Use Energy Demand by Sector in 2005

(Percent)

	Control Case/ 1988 High Case	Control Case/ 1988 Low Case
Residential	3	1
Commercial	-2	2
Industrial	-15	5
Transportation	-4	-
Non-Energy	-1	1
Total	**-7**	**2**

- Less than 0.5.

4.3 End Use Energy Demand By Fuel and Region

Fuel use varies considerably across regions, reflecting the availability and use of natural gas, and relative energy prices of each region. As seen in Figure 4-9 and Table 4-13 the absence of natural gas in the Atlantic region results in a larger share of oil used for non-transportation purposes. In Quebec, where electricity prices are lower than in many other provinces, and where there is less acceptance of natural gas for residential uses, the electricity share is almost twice as high as in other provinces. In Ontario, the large industrial sector and its use of natural gas, combined with penetration of this fuel in the residential and commercial sectors, make natural gas the most important fuel in that province. In the Prairies, natural gas dominates in all provinces, although electricity's share in Manitoba (where electricity prices are relatively low) is much higher than in the other Prairie provinces. In British Columbia, the role of the pulp and paper sector and its use of wood wastes results in a much higher share of renewables than in other provinces.

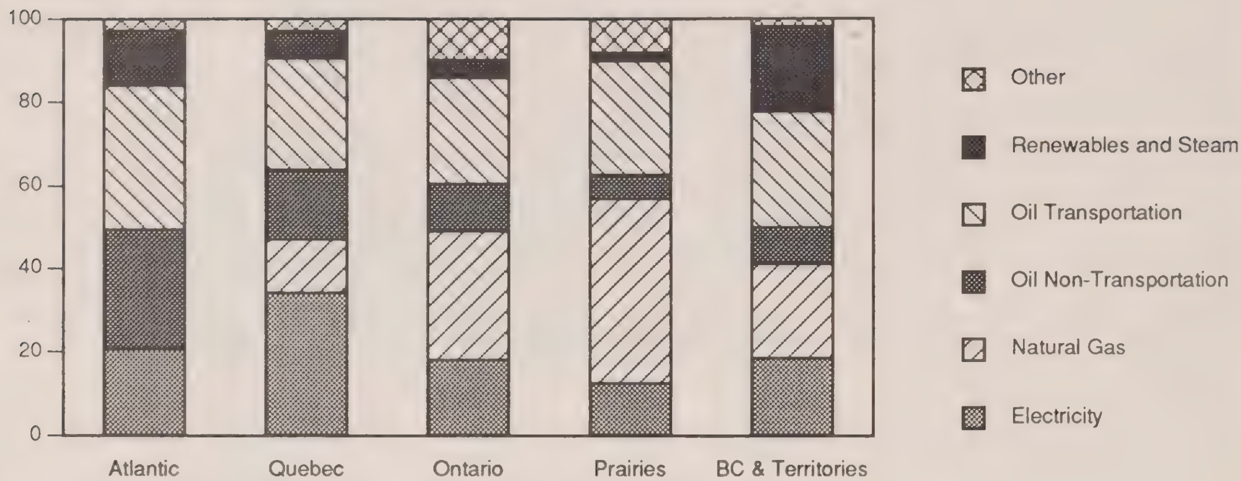
On a regional basis, we have included the Vancouver Island natural gas pipeline, with throughput beginning in 1991. We have not included any other major changes to existing energy distribution systems in the projection.

Table 4-14 shows the levels of total energy demand by region in 1989 and 2010 for the Control Case. The regional growth in end use demand strongly reflects the relative economic and household growth of the regions. As efficiency improvements occur, energy

Figure 4-9

End Use Fuel Shares by Region in 1989

(Percent)



Source: Appendix Table A4-5.

Table 4-13

End Use Fuel Shares by Region 1989

(Percent)

	Atlantic	**Quebec**	**Ontario**	**Prairies**	**B. C. and Territories**
Electricity	21	34	18	12	18
Natural Gas	-	13	31	48	23
Oil Non-Transportation	29	17	12	11	11
Oil Transportation	34	26	25	23	26
Renewables[a] and Steam	13	7	4	2	20
Other[b]	3	3	10	4	2
Total	**100**	**100**	**100**	**100**	**100**

Notes: The numbers on this table have been rounded.

[a] Renewables includes wood, wood waste, solar, wind and municipal solid waste.

[b] Other includes coal, coke, coke oven gas and natural gas liquids.

Table 4-14

End Use Energy Demand by Region

	(Petajoules)			Average Annual Growth (Percent)
	1989	2000	2010	1989-2010
Atlantic	536	586	620	0.7
Quebec	1580	1768	1954	1.0
Ontario	2696	3051	3479	1.2
Manitoba	249	258	273	0.4
Saskatchewan	282	295	309	0.4
Alberta	1287	1605	1936	2.0
British Columbia	997	1113	1219	1.0
Canada	**7627**	**8675**	**9790**	**1.2**

Note: The numbers on this table have been rounded.

demand growth lags economic or household growth in all provinces. Ontario accounts for approximately 35 percent of end use demand in Canada - a share that does not change over the projection period. A low rate of household formation and lower than average economic growth in Manitoba and Saskatchewan are the main factors behind those provinces' low end use energy demand growth. In Alberta, energy demand growth reflects the increasing natural gas and coal use for bitumen production. Without this fuel use, Alberta's end use demand would grow by less than 1.5 percent per year.

Renewable energy has strong regional concentration as shown in Figure 4-9. We discuss below our outlook for the role of alternative energy, followed by a more detailed discussion of fuel demand by region.

4.3.1 Alternative Energy

We use the term alternative energy to refer to renewable sources - such as wood, wood wastes, solar and small-scale wind - and less conventional sources such as municipal solid waste.

In 1989, these sources accounted for just under 7 percent of Canada's end use energy requirements. Of the total 509 petajoules of alternative energy, just over 80 percent, or 411 petajoules, was wood waste used in the pulp and paper and forestry sectors, 19 percent represented wood use in the residential sector, while solar and municipal waste accounted for under one percent.

Measuring use of alternative or renewable energy in the residential and commercial sectors poses certain difficulties. In some instances, wood or solar may not be the primary source of energy. Use of passive solar or infrequent use of wood may be measured as conservation (as it reduces requirements for conventional, measured energy sources) rather than as alternative energy consumption. Thus it is likely that our estimates understate the use of some of these alternative energy forms, although their impact on the use of conventional non-renewable energy sources is captured in our projections.

The demand for alternative energy will be influenced by how all forms of energy are priced. Essentially, there are two bases of cost accounting according to which prices may be determined. One is "social cost accounting", wherein the price of energy would recover not only direct costs of production, but also other costs which the production of this energy imposes on parties other than the producers of the energy. An example is the pollution cost of fossil-fueled power plants, or the loss of fishing benefits from any disruptive impacts of a hydro dam. Pricing based on social cost would account for all of these factors; it would not include any subsidies, and it would reflect the social cost of the next unit of energy to be produced.

The other basis of pricing is commercial cost accounting, which reflects how the market place views supply costs and determines market prices, given current taxes and subsidies. On this basis, market prices include the energy suppliers' direct production costs, any subsidies received, taxes paid, and may reflect a mixture of incremental and historical costs.

The relationship between the prices of alternative energy and conventional energy could differ if energy were priced on the basis of social costs rather than on a commercial or market basis. We use the market pricing approach, because our primary objective is to estimate demand and supply of energy in the context of anticipated market price behaviour.

Given our outlook for oil, natural gas and electricity prices, we expect very little change in the share of alternative energy forms. Except for the use of wood in the residential sector and wood waste by industry, existing technology for most alternative energy is still expensive compared with that of conventional energy, when priced on a market basis. Therefore, the share of these energy sources does not increase. We recognize, however, that pricing mechanisms and tax policies could change, as could individual preferences in favour of using alternative energy forms. There may also be technological breakthroughs which enhance the viability of alternative energy. These factors could increase the share of these energy sources to levels higher than we have projected.

The wood waste share of industrial end use demand rose from 14 percent in 1978 to 16 percent in 1989; however, by 2010 that share is projected to decline to about 11 percent. The declining importance of wood waste as a source of energy for industrial output is due to the pulp and paper industry's projected falling share of industrial gross domestic product and to its increased use of thermomechanical pulping (TMP).

Encouraged by rapidly rising oil prices between 1973 and 1981 and the Canadian Oil Substitution Program , residential wood use increased to 8 percent of total residential energy use by 1986 but declined to 6 percent in 1989. In the Atlantic region and in Quebec the increase was more dramatic as wood use rose to 26 percent and 12 percent, respectively, of residential end use demand by 1986. However, by 1989 the share of wood dropped to 19 percent in the Atlantic region and to 10 percent in Quebec. Over the outlook period, the world oil price is not projected to reach its 1981 level in real terms and, in the absence of further government incentives, the wood use share of residential energy demand is projected to remain unchanged at 6 percent between 1989 and 2010.

Municipal solid waste can be burned to produce steam for process heat or to generate electricity, or it can be a source of biogas for subsequent use in heating buildings or generating electricity. Biogas, consisting mostly of methane, carbon dioxide and hydrogen sulphide, is now being extracted from a municipal landfill site in Richmond, British Columbia and burned in a kiln at Canadian Cement Lafarge. The landfill gas provides about 13 percent of the energy requirements of the kiln. If not extracted and properly burned it is a dangerous pollutant. Negotiations are underway to extract methane gas from a municipal solid waste site at a quarry near Montreal for heating Montreal municipal offices.

The decision to build a plant to burn municipal solid waste is only partly influenced by the price of alternative fuels. Another factor is the increasing difficulty of finding suitable and environmentally acceptable dump-sites in the larger urban areas. Our projections include about 12 petajoules of energy from municipal solid waste in commercial and industrial uses by 2010. This is 2 percent of alternative energy use. We feel that non-price factors will largely determine the use of this technology.

In the Control Case, we project that alternative energy sources will account for about 6 percent of Canada's total end use energy demand by 2010, compared to their 6.7 percent share in 1989.

4.3.2 Atlantic Region

The Atlantic region has access to virtually no natural gas. Fuel choices are mainly oil and electricity in all sectors, wood waste and coal in the industrial sector, and wood in the residential sector. Since the oil price shocks of the 1970s, this region has made major reductions in its dependence on oil, largely through increased use of wood and wood waste.

End use demand in the Atlantic region is projected to increase by 0.7 percent annually over 1989 to 2010. In the same period, improvements in energy intensity of 1.1 percent per year are expected.

In our projections, we anticipate a continued decline in oil's share of the region's end use demand from 63 percent in 1989 to 60 percent in 2010. All of this decline occurs in the use of oil for non-transportation uses; the share of oil for transportation use is stable at close to 34 percent of total end use energy.

By 2010, our projections show electricity's share at 26 percent, up from 21 percent in 1989, as the residential, commercial and industrial sectors increase their electricity use.

Given the relatively low oil prices, as compared to oil prices of the mid-1970s to early 1980s, we have not allowed for major increases in the share of wood for residential heating, which remains close to 19 percent of the sector's needs. Physical resource constraints and increased use of thermomechanical pulping reduce the share of renewables in Atlantic industrial demand. As a result, renewables energy use in 2010 accounts for 10 percent, down from 13 percent in 1989.

The projected levels and shares of end use demand (including transportation demand) for the Atlantic region are shown in Figure 4-10.

4.3.3 Quebec

During the 1970s and early 1980s there was intense competition between natural gas and electricity to capture both new markets and conversions from oil. While this competition has lessened, Hydro-Québec is still pursuing incentive programs for certain industrial markets. As a result, the flexibility of fuel choice in industrial plants exceeds that of any other Canadian province, with many plants able to select heavy fuel oil, natural gas or electricity. Moreover, approximately six percent of the housing stock in Quebec has dual heating capability.

Fuel switching will depend more on relative prices than on continuing subsidies or incentives, as any new incentive programs are expected to be very limited.

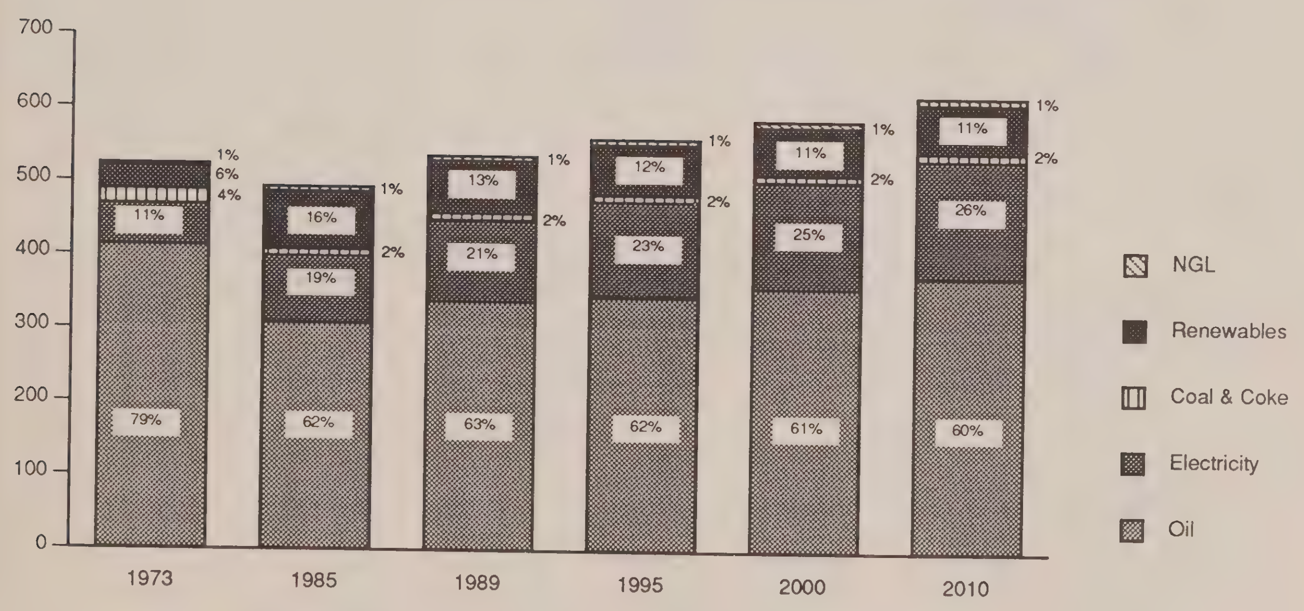
Quebec's requirements for end use energy are projected to increase by 1.0 percent annually over the period 1989 to 2010. Energy use per unit of output declines on average by 1.2 percent per year.

Given the importance of electricity use in the province, the expectation that consumer preferences will limit natural gas growth in the residential and commercial sectors, and the projected significant increase in the natural gas price relative to that of heavy fuel oil in the industrial sector, the market share of natural gas is expected to decline. Industrial natural gas use increases modestly through 1995, but declines steadily thereafter. The price of natural gas to industrial users exceeds the heavy oil price by more than 10 percent in 1995, and the differential continues to widen throughout the projection period. We have assumed continued, though slow, conversion off oil in the residential and commercial sectors. However, the non-transportation oil share of end use energy increases from 17 percent in 1989 to 20 percent in 2010, mainly from the projected increase in the demand for oil in the

Figure 4-10

End Use Energy Demand by Fuel
Atlantic

(Petajoules)

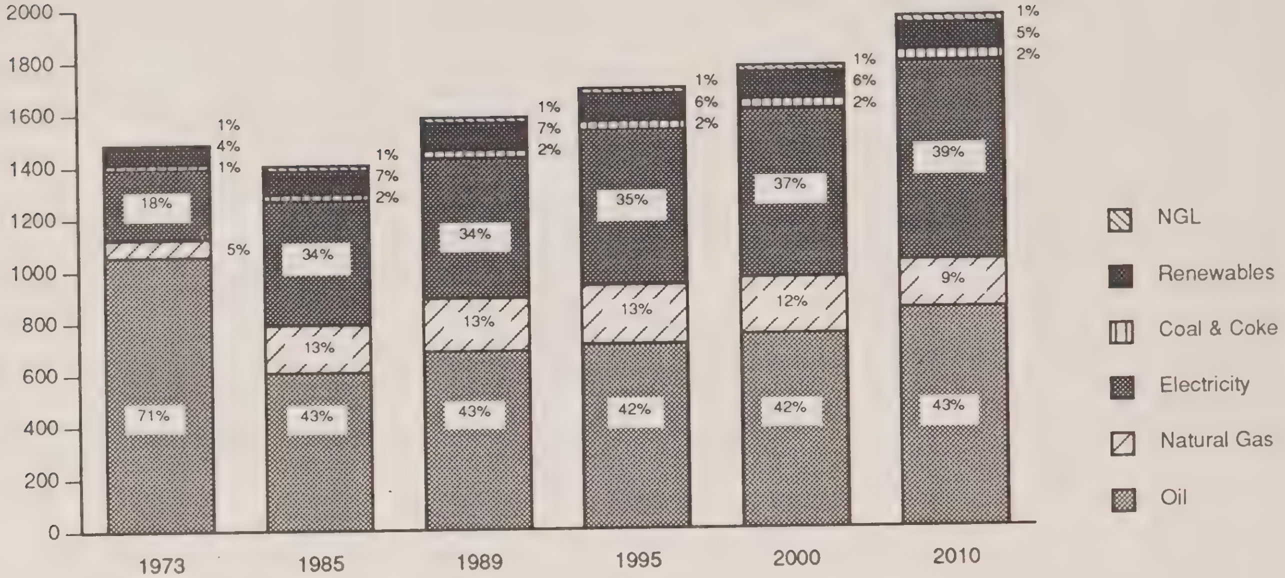


Source: Appendix Table A4-5.

Figure 4-11

End Use Energy Demand by Fuel
Quebec

(Petajoules)

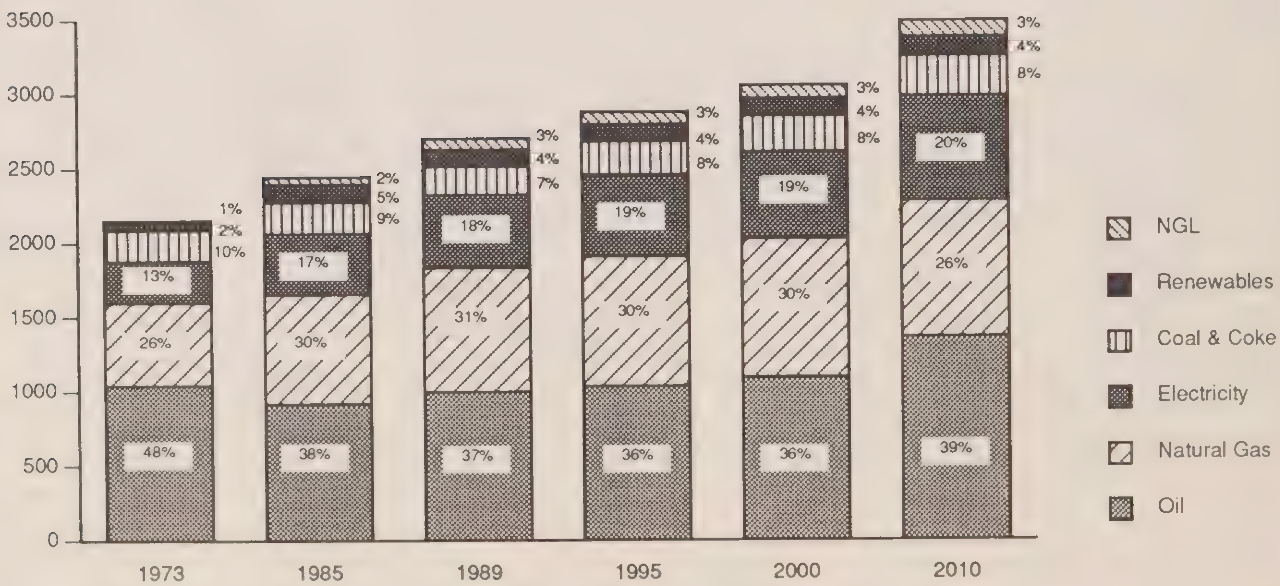


Source: Appendix Table A4-5.

Figure 4-12

End Use Energy Demand by Fuel
Ontario

(Petajoules)



Source: Appendix Table A4-5.

industrial sector. Electricity accounts for 39 percent of end use demand by 2010, up from 34 percent in 1989. Oil used for transportation purposes declines from 25 percent of the market in 1989 to 23 percent in 2010 (see Figure 4-11).

4.3.4 Ontario

Ontario's end use demand grows more rapidly than that of any province except Alberta. The province's energy requirements increase by 1.2 percent annually. The energy intensity declines by 1.4 percent per year from 1989 to 2010. The province's industrial sector accounts for much of the growth in provincial end use energy demand. This sector's share of Ontario's energy use rises from 34 percent in 1989 to 38 percent by 2010.

We expect the market share of electricity to grow modestly from 18 percent of total end use energy demand in 1989 to 20 percent in 2010, reflecting the impact of Ontario Hydro's demand management programs on growth in electricity demand. Without this program the share of electricity would have been slightly higher. Oil's share increases from 37 percent in 1989 to 39 percent in 2010. This increase is largely due to the growth of oil demand in the industrial sector resulting from the projected decrease in the heavy fuel oil price relative to that of natural gas. In the residential and commercial sectors, we have assumed continued conversions off oil, and that new markets will use mainly natural gas or electricity. The natural gas share of end use energy demand decreases from 30 percent in 1989 to 26 percent in 2010 mainly because of the decline in its share of the industrial energy market (see Figure 4-12). There is slow growth in industrial natural gas demand in Ontario through the year 2005, as the natural gas price rises to 110 percent of the heavy fuel oil price. The growth from the year 2000 to 2005 is very modest, and after 2005, industrial natural gas demand declines steadily, as the price of gas relative to heavy fuel oil rises to 120 percent in 2010.

4.3.5 Prairie Provinces

Our projections show end use demand in the Prairie region growing at 1.7 percent annually over 1989 to 2010. Alberta accounts for 71 percent of the region's energy use, and thus dominates trends at the regional level. The increasing demand for coal and natural gas for energy-intensive bitumen projects results in only a small decline in projected aggregate energy intensity.

In 1989, oil used for non-transportation purposes accounted for only ten percent of end use demand. The total share of oil was 33 percent. This share declines to 26 percent in 2010 because oil use in transportation remains stable.

Little growth in transportation energy demand is expected because car and truck stock fuel efficiencies improve steadily (as older vehicles are replaced), and the stock itself is assumed to grow slowly (see Section 4.2.6 for a discussion of the transportation sector).

The pattern of fuel shares is affected by the assumptions concerning coal use in bitumen projects. Coal's share increases from under one percent in 1989 to almost 7 percent in 2010; its annual average growth is 16 percent over the projection period. Little change in the electricity share is anticipated; it remains at about 12 percent of the end use energy demand between 1989 and 2010. The share of natural gas increases from 33 percent of total energy demand in the Prairie region in 1989 to 45 percent in 2010 mainly because increased amounts of natural gas are required for bitumen projects (see Figure 4-13).

4.3.6 British Columbia, Yukon and Northwest Territories

British Columbia's end use energy demand is projected to grow from 1989 to 2010 at 1.0 percent annually. Energy intensity declines by just over one percent per year.

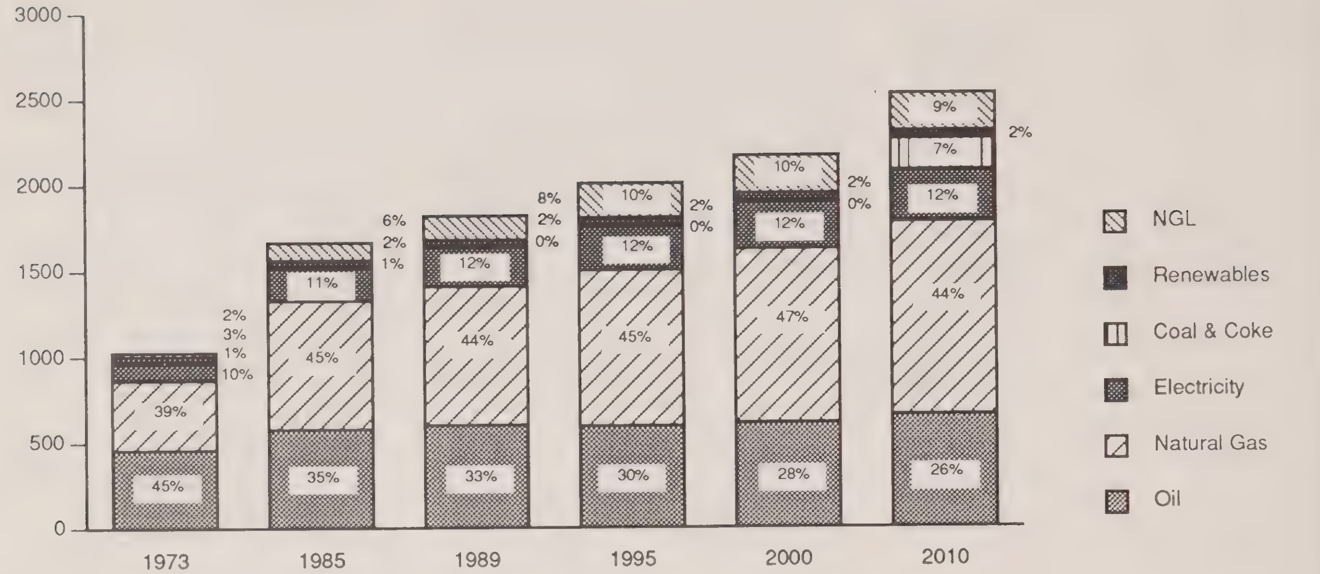
Over the projection period there is a relatively small increase in electricity's share - from 18 percent in 1989 to about 22 percent in 2010 - in part reflecting the impact of B.C. Hydro's demand management programs, without which the share of electricity would be greater. Oil for non-transportation uses accounted for only 10.6 percent of provincial demand in 1989 and increases marginally to slightly over 11 percent by the year 2010 as heavy fuel oil prices decline relative to natural gas. Oil for transportation use declines from 26 percent of total energy use to about 25 percent in 2010 for similar reasons as discussed for the Prairies.

The share of renewables, which are dominated by wood waste, declines from about 20 percent of provincial energy demand in 1989 to about 18 percent in 2010. As the pulp and paper sector faces resource constraints and as wood waste is replaced by electricity, we expect a decline in the role of wood waste in meeting the province's energy needs (see Figure 4-14).

Figure 4-13

End Use Energy Demand by Fuel
Prairies

(Petajoules)

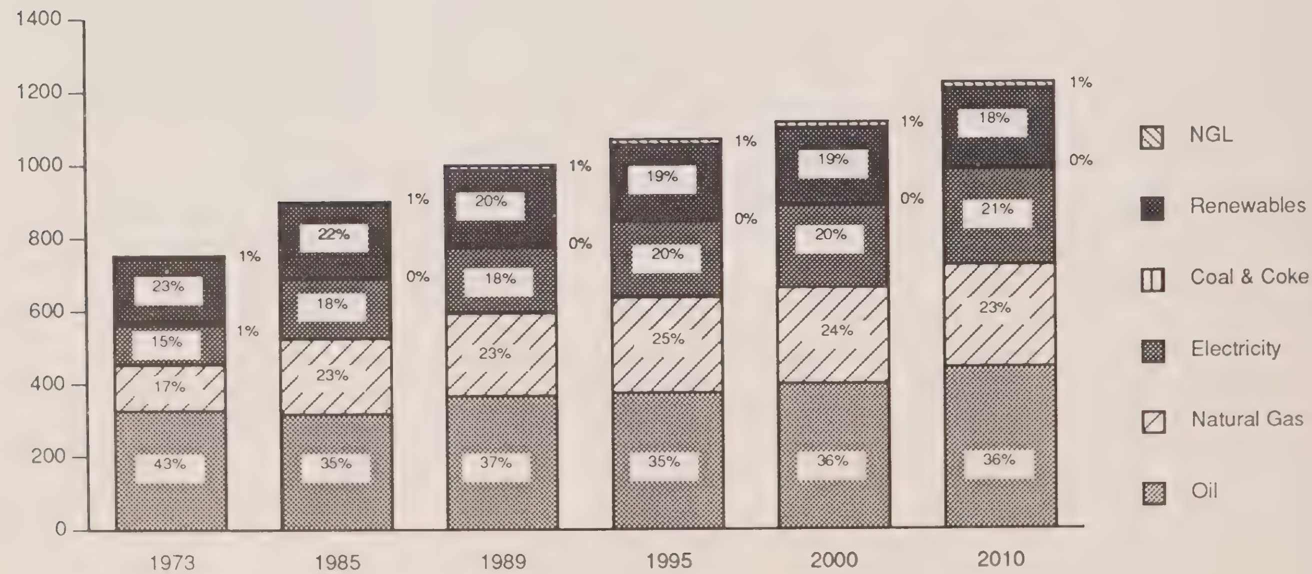


Source: Appendix Table A4-5.

Figure 4-14

End Use Energy Demand by Fuel
BC & Territories

(Petajoules)



Source: Appendix Table A4-5.

Yukon and the Northwest Territories rely on oil and electricity for all of their energy use. There have been some recent small scale electricity projects using wind, but the bulk of energy needs are still met through conventional sources. We do not anticipate substantial changes in the fuel mix. However, small-scale renewable projects may take on a more important role in the future.

4.3.7 Canada

End use energy demand grows by 1.2 percent in Canada from 1989 to 2010, and energy intensity declines by just over 1.2 percent per year over the same period.

As shown in Table 4-15 and Figure 4-15, we expect fuel shares to remain relatively stable through the projection period. The oil share declines slightly, reflecting slow growth in oil demand for transportation use. The impact of slow growth in transportation use is mitigated by the switching from natural gas to heavy fuel oil in the industrial sector. Coal's share increases as energy requirements for bitumen projects grow. This is discussed in more detail in Chapter 9.

Table 4-15

End Use Energy Demand and Fuel Market Shares

	1989	2000	2010
		(Petajoules)	
Levels			
Electricity	1550	1869	2189
Natural Gas	2073	2413	2483
Oil	2983	3197	3668
Renewables[a]	533	558	581
Coal, Coke, Coke Oven Gas	237	292	496
NGL	251	347	373
Total	**7627**	**8676**	**9791**
		(Percent)	
Shares			
Electricity	20	22	22
Natural Gas	27	28	25
Oil	39	37	37
Renewables[a]	7	6	6
Coal, Coke, Coke Oven Gas	4	3	6
NGL	3	4	4
Total	**100**	**100**	**100**

Notes: The numbers on this table have been rounded.
[a] Includes hog fuel and pulping liquor, wood, solar, municipal solid waste and steam.

The fuel shares are the result of projected energy demand for specific end uses (including the anticipated efficiency improvements in those end uses), and energy price relatives, which influence the choice of fuel for many uses. Clearly certain end uses can be met by only one or a limited range of fuels, for example, lighting and plug loads can use only electricity. Thus, relative prices have a greater impact on fuel shares for some sectors and uses than for others.

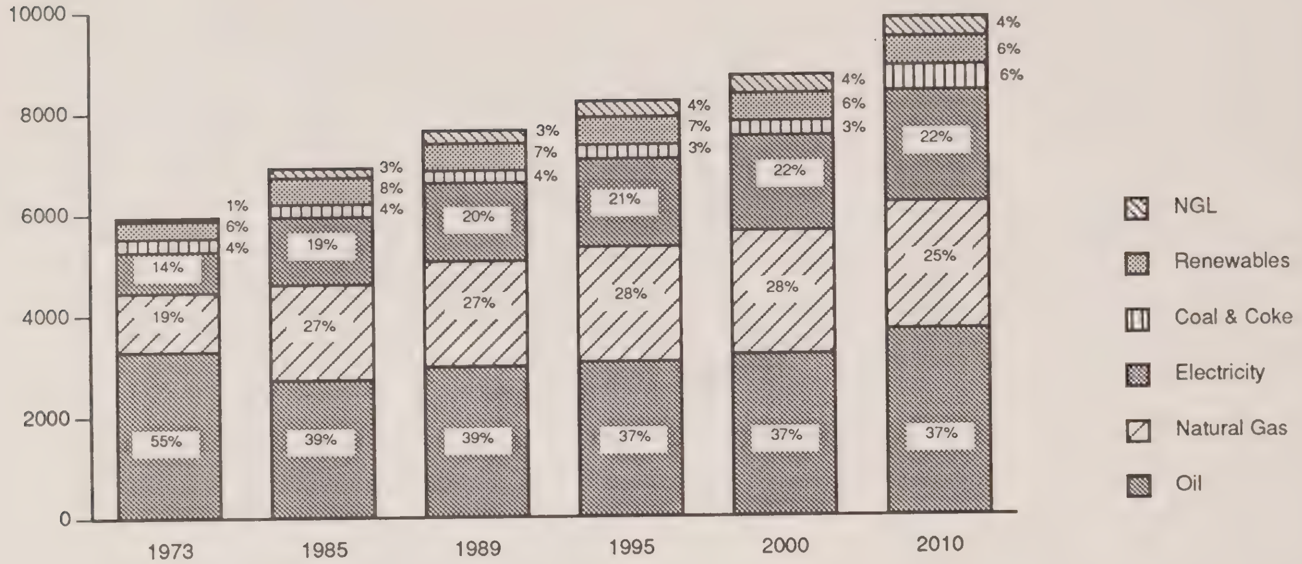
In this projection the greatest uncertainty regarding fuel shares relates to the use of natural gas and heavy fuel oil in the industrial sector. Since industrial gas use (excluding fuel for bitumen) accounted for over 10 percent of total end use demand in 1989, shifts in the fuel shares in this sector can have a significant impact on the overall natural gas demand. Industrial gas use in Ontario and Quebec together accounted for 6 percent of total Canadian end use demand in 1989. Our price projections have the industrial end use natural gas price rising relative to that of heavy fuel oil in these two provinces, exceeding it in 2010 by 20 and 30 percent, respectively. As a consequence, we have projected that industrial gas users would switch from natural gas to heavy fuel oil, particularly during the last ten years of the projection. There are a number of uncertainties which could cause a different outcome. Among these are:

- there is large uncertainty surrounding our price projections for both oil and natural gas;
- although we have increased the price of heavy fuel oil to reflect a lower sulphur content, it is possible that more stringent environmental regulations could make use of heavy fuel oil unattractive, even at the price differentials in our projection;

Figure 4-15

End Use Energy Demand by Fuel
Canada

(Petajoules)



Source: Appendix Table A4-5.

- increased demand for heavy fuel oil would also necessitate an expanded distribution network from that which currently exists, and importation of oil product, as Canadian refineries will not be able to meet this domestic demand (see Section 7.4).

All these factors could result in a higher share for natural gas than we have projected.

The inset table compares the Control Case in 2005 with the High and Low Cases from the 1988 Report. Relative to the 1988 High Case:

- the Control Case shows lower electricity demand, due largely to lower economic growth than in the 1988 High Case,
- natural gas demand is 13 percent lower, largely due to the higher price relative in the Control Case and the shedding of industrial load,
- oil demand is somewhat higher, reflecting the nearly offsetting impacts of higher industrial heavy fuel oil demands and slightly lower transportation requirements,
- the large difference in coal demand (38 percent) is related to the much greater use of coal for bitumen production in the 1988 High Case,
- lower wood use is due to our assumption in the Control Case that there will be little change in the current *level* of wood use for residential heating purposes, relative to an assumption of a fairly constant share in the High Case. Lower wood waste consumption is the result of slower growth for the pulp and paper sector than in the 1988 Report, increased penetration of TMP and CTMP, and recycling,
- the difference in the other fuels category is largely due to a more robust view for NGL demand for petrochemical uses in the current projection.

The differences with the Low Case are less pronounced, as the economic growth outlooks are similar. Coal use for bitumen is similar, thus there is not as much variance between the Control and Low Cases as with the High Case.

Differences in End Use Energy Demand by Fuel in 2005

(Percent)

	Control Case/ 1988 High Case	Control Case/ 1988 Low Case
Electricity	-5	6
Oil	2	5
Natural Gas	-13	3
Coal, Coke, Coke Oven Gas	-38	-2
Steam	-14	1
Wood	-24	-27
Wood Waste	-11	-9
Other	22	29
Total	**-7**	**2**

Table 4-16

Distribution of Primary Oil Demand by Product

(Percent)

	1989	2010
Aviation Fuels	6	6
Motor Gasoline	33	29
Light Fuel Oil and Kerosene	9	5
Diesel Fuel Oil	20	20
Heavy Fuel Oil	13	18
Asphalt	4	5
Other	15	17
Total	**100**	**100**

Note: The numbers on this table have been rounded.
Source: Appendix Table A10-1.

The differences between wood and wood waste are due to the same factors discussed above.

4.4 Primary Energy Demand

4.4.1 Primary Demand for Oil

Primary demand for oil consists of the quantities of refined products required for end use, own use and conversions. End use requirements - the use of oil products for non-energy purposes and for the residential, commercial, industrial and transportation sectors - constitute the largest component of primary oil demand. Oil products used by the energy supply industry and the requirements for electricity and steam production make up the remaining share of primary oil demand. Overall, primary demand for oil from 1989 to 2010 increases by 0.9 percent annually (Table 4-17). Of all end use sectors, transportation remains the largest user of oil throughout the projection period although its share of primary oil demand decreases from 56 percent in 1989 to 51 percent in 2010. Between 1989 and 2010:

- the share of light fuel oil and kerosene declines considerably;
- the share of diesel fuel oil remains unchanged, but that of motor gasoline falls;
- the share of heavy fuel oil increases (see Table 4-16).

Light fuel oil and kerosene lose market share in the residential and commercial sectors to natural gas and electricity. The reduction in oil demand in the residential and commercial sectors is shown in Table 4-17. During the projection period, light fuel oil and kerosene requirements for the two sectors combined decrease by 1 percent annually.

The motor gasoline share of primary oil demand declines from 33 percent in 1989 to 29 percent in 2010, as a result of slow growth in the stock of gasoline vehicles and continuing improvement in their fuel efficiency. There is little change in the share of diesel fuel oil in primary oil demand (see Section 4.2.6).

We project considerable improvement in the competitive position of heavy fuel oil relative to natural gas in the industrial sector, as natural gas prices increase more rapidly than that of heavy fuel oil. This causes heavy fuel oil requirements in the industrial sector to rise by 5.2 percent annually between 1989 and 2010, substantially higher than the growth of total primary oil demand. Most of this growth occurs after 1995. Between 1989 and 1995 industrial heavy fuel oil demand grows by 1.8 percent per year, increasing to 3.5 percent per year from 1995 to

Table 4-17

Primary Demand for Oil by Use

(Petajoules)

	1989	2010
Sectoral Demand		
Residential	285	206
Commercial	109	104
Industrial	327	723
Petrochemical	120	173
Transportation	1917	2118
Other Non-energy	224	344
Total End Use	**2982**	**3668**
Own Use and Conversions		
Energy Supply Industry[a]	237	290
Electricity Generation	176	135
Steam Production	2	2
Butanes Used for Blending	-58	-58
Refinery LPG	59	76
Total Own Use and Conversions	**416**	**445**
Total Primary Demand	**3398**	**4113**

Notes: The numbers on this table have been rounded.
[a] Includes refinery LPG own use.

Source: Appendix Table A10-1.

Definitions of Primary Oil, Natural Gas and Natural Gas Liquids

Primary Oil

- all refined petroleum products (end use)
- pentanes plus
- propane and butanes from refineries

Primary Natural Gas

- end use natural gas
- fuels for: steam and electricity generation; transportation and distribution; reprocessing plants
- excludes reprocessing shrinkage (ethane)

Primary Natural Gas Liquids

- propane and butanes from gas plants
- reprocessing shrinkage (ethane)

2000. As the price differential between industrial natural gas and heavy fuel oil widens, the demand for heavy fuel oil increases more rapidly. From the year 2000 to 2010, the growth in industrial heavy fuel oil averages 7.6 percent per year. As a result, the share of heavy fuel oil in total primary oil demand increases from 13 percent in 1989 to 18 percent in 2010.

4.4.2 Primary Demand for Natural Gas

As is the case for oil, end use demand accounts for the largest share of primary natural gas demand (Table 4-18). Primary demand for natural gas also includes fuel required to produce steam and electricity, and to operate pipelines and reprocessing plants[1].

During the projection period, primary demand for natural gas increases at an average annual rate of 0.8 percent. This growth rate is similar to that of end use requirements.

Natural gas used to generate electricity is for domestic requirements only and is used mainly in the industrial sector rather than by electrical utilities. The extent of this use of natural gas depends on end use demand for electricity, how this electricity is generated, and the extent to which independent power production occurs. In 1989, Alberta used more than 70 petajoules and was the province where

1 For purposes of the analysis presented in this Chapter, natural gas consumed as a result of reprocessing shrinkage is excluded from primary demand for natural gas and is instead included in primary demand for natural gas liquids, discussed in Section 4.4.3. However, the reverse is true in Chapters 6 and 10 where the supply/demand balance for energy is discussed.

Table 4-18

Primary Demand for Natural Gas
(Petajoules)

	1989	2010
End Use	2073	2483
To generate electricity[a]	140	122
Pipeline fuel and loss	180	226
Reprocessing fuel	14	32
Primary Demand[b]	**2407**	**2863**

Notes: The numbers on this table have been rounded.
[a] Natural Gas used to produce steam included.
[b] Excludes reprocessing shrinkage.

Source: Appendix Table A10-1.

Table 4-19

Primary Demand for Natural Gas Liquids[a]
(Petajoules)

	1989	2010
End Use Demand	**251**	**373**
Propane and Butanes	130	189
Ethane	121	184
Own Use and Conversions	**64**	**67**
Energy Supply Industry	6	9
Butanes Used for Blending	58	58
Sub-total	**315**	**440**
Less Refinery LPG[b]	63	82
Primary Demand for Ethane and Gas Plant NGL	252	358

Notes: The numbers on this table have been rounded.
[a] Excludes pentanes plus. Pentanes plus are included in crude oil.
[b] End use demand assumed to be met by refineries.

Source: Appendix Table A10-1.

the greatest amount of natural gas was used for electricity generation; national requirements totalled 136 petajoules. During the projection period Alberta remains the principal user of natural gas for electricity generation, accounting in 2010 for 66 petajoules.

Pipeline fuel and losses are related to the transportation of natural gas for export, and to the transmission and distribution of gas to meet domestic requirements.

The amount of natural gas required for the transportation of exported natural gas reflects our outlook for natural gas exports. In 1989, these transportation requirements amounted to 34 petajoules and reach 68 petajoules by 2010.

Fuel required for the transmission of natural gas to domestic markets increases from 95 petajoules in 1989 to 102 petajoules in 2010. The amount of natural gas used for distribution to end users is lower than the amount required for transmission. From 51 petajoules in 1989, distribution requirements increase to 57 petajoules in 2010.

4.4.3 Primary Demand for Natural Gas Liquids

Table 4-19 provides primary demand for natural gas liquids (NGL) by use. For purposes of primary demand analysis, natural gas liquids are defined to include only propane, butanes and ethane.[1] Propane and butanes are produced by gas plants and refineries, and ethane is a by-product of natural gas. Propane and butanes produced by refineries are not counted as part of primary natural gas liquids demand, as

1 Pentanes plus are included with crude oil and are therefore excluded here.

they are treated as part of primary oil demand.

As with oil and natural gas, end use requirements constitute the main component of primary demand for NGL. Ethane, which is used as a petrochemical feedstock, accounts for about 50 percent of the total end use for NGL. From 1989 to 2010, ethane demand increases by 2 percent annually. Propane and butanes for non-energy use, and propane used in the transportation sector also contribute to increased NGL end use demand. From 1989 to 2010, end use demand for total NGL increases at an annual rate of 2 percent, although the annual growth of residential, commercial and industrial NGL use is only 0.6 percent.

Table 4-20

Primary Demand for Coal

(Petajoules)

	1989	2010
End Use Demand[a]	55	240
Electricity Generation[b]	966	1252
Steam Generation	1	0
Other Conversions and Own Use	4	6
Coal to Coke Conversion	172	242
Primary Demand	**1198**	**1740**

Notes: The numbers on this table have been rounded.
[a] Excludes coke and coke oven gas.
[b] Fuel for electricity exports included.

Source: Appendix Table A10-1.

Primary demand for ethane and gas plant NGL amounted to 252 petajoules in 1989. Growth in demand results in natural gas liquids use to increasing to 358 petajoules in 2010.[1]

4.4.4 Primary Demand for Coal

In addition to end use demand, primary demand for coal includes requirements for the production of steam and electricity, own use and conversion of coal into coke (Table 4-20).

Unlike other fuels, the main component of primary coal demand is not end use demand; rather it consists of requirements for the generation of electricity, especially in Alberta, Ontario, Saskatchewan and Nova Scotia (see Chapter 5). Coal used for conversion to coke is the second largest component of primary demand. Coke is used mainly by the iron and steel industry.

From 1989 to 2010, primary demand for coal increases at an average annual rate of 1.8 percent. This rate of growth is the result of increased requirements for the generation of electricity and the use of coal in bitumen production in Alberta. In the Control Case, we assume that coal will be used for bitumen production beginning in 2001 (see Chapter 9).

4.5 Concluding Comments

In the Control Case, end use demand grows at an average annual rate of 1.2 percent, from 1989 to 2010. Primary energy demand also grows by 1.2 percent per year over this period. Since we project economic growth at a rate of just under 2.5 percent per year, this implies a decline in energy intensity of about 1.2 percent annually.

A number of factors, including income, output and energy-using capital stock, combine with efficiency improvements to determine sectoral energy demand growth. With annual household growth averaging only 1.4 percent over the period, total residential energy demand grows at only 0.5 percent per year. Commercial sector real GDP increases on average at 2.0 percent per year from 1989 to 2010 and commercial energy demand grows by about 1.0 percent. Industrial output grows at 2.6 percent on average, and industrial energy demand averages just under 2 percent per year. The car stock increases by 1.5 percent per year, and the truck stock more rapidly (2 percent), with more growth in diesel than gasoline trucks. As a result, transportation energy demand increases by only 0.5 percent per year. Most of the growth occurs in diesel use. There is virtually no growth in gasoline demand. The decline in energy intensity is similar in all sectors:

1 Note that ethane is treated here as a component of primary demand for NGL. However, in the analysis of the supply/demand for energy in chapter 10, primary ethane requirements are included in the primary demand for natural gas.

- energy use per household declines by 0.9 percent per year;
- commercial energy intensity decreases by 1.0 percent per year, and industrial intensity by 0.7 percent;
- car stock fuel efficiency improves by 1.2 percent per year over the projection period, while truck stock efficiency improves by 1.1 percent.

Our analysis focuses on long-run trends in energy demand. As such, it analyzes the impact of the trend in economic growth and of factors which are structural in nature and which influence demand by changing the nature of energy-using equipment. In any given year, energy demand may vary depending on the weather and on short-run business cycles. We do not attempt to capture the influence of these factors in our projection.

We mentioned at the beginning of this Chapter that there is considerable uncertainty surrounding any long-run projection and that the Control Case is only one of a range of plausible outcomes over the next twenty years. There is uncertainty about the prospects for economic growth, energy prices, and the efficiency of energy use. (It can be argued that these are not unrelated factors. For example, energy prices can influence economic growth and vice versa, while both may influence the rate of efficiency improvement. Moreover, efficiency improvements can occur for other reasons as a result of technological change or other factors not specifically motivated by energy considerations.)

If there were no change in energy intensity from 1989 levels, total end use demand would be over 12 000 petajoules by the year 2010, 24 percent above the Control Case. On a sectoral basis, if energy use per household remained at its 1989 level, by the year 2010 **residential** energy demand would be about 20 percent, 350 petajoules, above the Control Case level. If we were to assume no change in **commercial** or **industrial** energy intensity relative to their 1989 levels, commercial and industrial energy demand would be about 23 percent (252 petajoules) and 17 percent (659 petajoules) higher respectively by 2010. In transportation, if there were constant energy use per car and truck, we estimate that the road sector would use some 530 petajoules more in 2010 than in the Control Case. This would represent an increase of 24 percent in **transportation** energy demand in the year 2010.

These levels represent an estimate of the upper bound of the impact of efficiency changes on energy demand, as they ignore the fact that new capital and equipment is more efficient than the existing stock. As the existing stock is replaced, and as new demands arise (from new households or businesses) there will be improvements in the efficiency of energy use even if there are no further improvements in the energy efficiency of new capital and equipment available now.

To establish a plausible range of energy demand growth it is necessary to consider a range for those variables which determine energy demand. There are various plausible combinations of economic growth, energy prices and efficiency improvement. Some combinations, such as high economic growth and high energy prices, would have offsetting impacts on energy demand. High growth would generally lead to higher energy demand, although high energy prices would tend at the same time to promote energy efficiency and conservation. The high end of the range for energy demand may be characterized by high economic growth (especially if it were of an energy-intensive character) combined with low energy prices and slow efficiency improvements, while the low end of the range would be characterized by low economic growth (especially if it were of a much less energy intensive character), high energy prices and stronger efficiency gains.

In developing a bandwidth around our Control Case, we assess the impact of varying rates of economic growth, relative to that in the Control Case. If we assume a combination of lower energy prices with a higher economic growth outlook, on the one hand, and higher energy prices with a lower growth outlook on the other, we can develop a bandwidth around the Control Case.

With respect to economic growth, we estimate that a range between 2 percent and 3 percent per year over the projection period represents a reasonable band. However, we recognize that 2 percent per year would likely lead to high unemployment and very low growth in disposable income. We think that there is a much higher probability that economic growth will be higher, rather than lower, than that in our Control Case.

The composition of economic output can also affect the level of energy demand, as energy use is much more intensive in the goods-producing industries than in service-producing industries. Our assumption that the industrial sector's share of total output will increase over the projection period is contrary to the

outlook of many analysts. In the Control Case the industrial share of real GDP increases from 33 percent in 1989 to 36 percent in 2010. If the shares of industrial and commercial output were maintained at their 1989 levels, we estimate that total end use demand would be 2 percent, or about 200 petajoules, lower by 2010. [1]

Figure 4-16 shows our estimate of a bandwidth of uncertainty around Control Case end use demand levels. We developed this bandwidth judgmentally, by roughly estimating energy demand associated with plausible combinations of low (high) economic growth, high(low) energy prices and high(low) rates of efficiency improvements. There is a narrower band in the near term (less than 5 percent in either direction) than in the longer run, as energy demand in the near term is heavily influenced by the stock of energy using capital that is now in place and its characteristics do not change quickly. Energy using equipment generally has a life of from several years to several decades. It is unlikely that there would be major replacement of existing energy using stock well before the end of its useful life. The bandwidth increases over time, to 15 percent above or 10 percent below Control Case levels in the year 2010. This reflects the widening range for plausible economic activity and prices over time and the cumulative impact of changes in capital stock and behaviour (i.e. conservation and efficiency impacts).

On balance, we think there is a greater probability that energy demand growth may be higher, rather than lower, than we have projected over the next twenty years, given the efficiency and conservation gains we have built into our estimates. However, major structural changes reflecting worldwide environmental concerns could lead to even greater gains in efficiency and conservation than we have included (see Section 11.7.1).

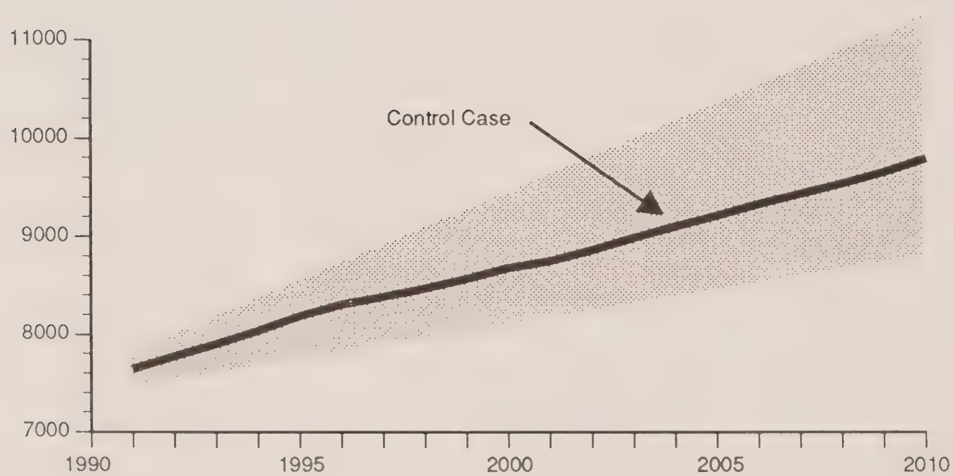
The plausible range of energy demand in this Report is wider than the difference between the two cases in our 1988 Report. In the 1988 Report our two cases included offsetting influences on energy demand, as we combined high growth with high oil prices, and low growth with low oil prices. The resulting range of end use demand between the two cases was close to 10 percent in 2005 in that Report, whereas in this report, by 2010, the bandwidth has a spread of 25 percentage points.

1 This simple calculation uses the same sectoral energy intensities in the year 2010 as in our Control Case (which implies the same relative importance of energy intensive industries in the industrial sector), it includes no change relative to the Control Case in the energy demand of sectors other than industrial and commercial and it assumes that the aggregate output level of the Control Case in 2010 could be achieved with the 1989 distribution of industrial and commercial output.

Figure 4-16

Range of End Use Energy Demand

(Petajoules)



Chapter 5

Electricity

The objective of this chapter is to highlight the main characteristics of the Canadian electricity industry and to set out our projections of electricity trade and of the expected changes required in electricity production to meet our projected demand in the context of a rapidly changing and uncertain regulatory, business and technological environment, notably in the areas of interprovincial and export trade and non-utility production.

We first describe the principal implications of our electricity demand projections (Section 5.1). We then assess the prospects for firm electricity trade between provinces and with the United States. This leads to a discussion of the need for new generating capacity in each province, and of the timing of major projects, taking into account the effect of demand management and the contribution of non-utility producers. We then discuss the outlook for interruptible exports and interprovincial trade. Finally, we present our projections of total electricity production and the need for fossil fuels, hydro and nuclear energy resources.

The total demand for electrical energy in each province is calculated by converting the end use demand projections from Chapter 4 from petajoules to gigawatt hours. Part of this demand is met by minor utilities, industrial self-generation, and independent power producers. We then calculate the major utility total firm commitments by adding our estimates of utilities' own use and losses, firm interprovincial sales, and firm exports. This total demand for electrical energy is used in conjunction with information on the utilities' generation expansion plans to project the supply scenario for each province. We simulate the planning and annual operation of the major provincial utilities in order to project fuel requirements and the timing of capacity additions, taking into account the required reserve capacity, so that the total peak demand and energy requirements, including interprovincial firm commitments and projected firm potential exports, are met in every year.

Surpluses in generating capability may result when anticipated loads do not materialize or when an economic advantage can be gained over the long term by capacity additions larger than short-term increases in demand might justify. Surplus production capability is determined as the difference between projected total annual average capability and total firm energy requirements. These surpluses are made available to neighbouring Canadian utilities and to interconnected utilities in the United States. Sales of these surpluses, largely on an interruptible basis, have in the past formed the bulk of interprovincial and international transactions. Consistent with the aim of maximizing the economic gains from interconnected operation, we have assumed that energy surpluses would be sold on the basis of transactions between markets with the lowest and highest incremental costs.

Utilities supply most Canadians with electricity. Their mandate is to ensure that adequate supplies of electricity are made available to reliably meet the needs of their firm customers at the least cost. Utilities therefore routinely forecast their customers' requirements for periods of fifteen to twenty years, to take into account the long lead times required for major projects. This sets a framework for the orderly planning and construction of new generating plants and transmission facilities, and the acquisition of the required fuels and other resources needed to meet the anticipated demand. Due to the high costs of new facilities and because of environmental constraints imposed upon the siting, construction, and operation of new generating plants and transmission lines, utilities are increasingly seeking to manage demand, i.e., to reduce demand and to shift demand from peak to off-peak periods, rather than solely trying to meet it by building new facilities. This study reflects our discussions with utilities on both their plans for managing demand and their projected capacity additions.

Privately-owned industries, institutions, and some individuals also produce electricity for themselves and some sell surplus to the utility system. We project that in some provinces they will assume a greater role in supplying electricity. In general, utilities are increasingly

prepared to buy electricity from non-utility producers at prices which reflect the utilities' own avoided production costs and under conditions compatible with sound system operations. Some provinces have called upon the private sector for proposals to supply electricity as a supplement to utility expansion, or will soon establish the institutional framework to do so. British Columbia, Alberta, Saskatchewan, Ontario, Quebec, Nova Scotia and Prince Edward Island have identified the potential for non-utility supplies. In general, we have used assumptions consistent with these policies where information was available; in other provinces we have not allowed for any independent generation. More details are set out in section 5.3.

Although there are many different kinds of transactions, we have, for simplicity, segregated electricity transactions into two broad classifications, interruptible and firm, depending on whether or not delivery is guaranteed. We made a further distinction between sales for which capacity (power) is reserved for the purchaser and sales where the delivery is primarily of bulk electricity (guaranteed energy without guaranteed capacity).

U.S. utilities are seeking new supplies to meet part of their projected firm electricity demand for the late 1990s. Several provinces have shown interest in advancing the in-service date of some of their new power plants in order to supply at least some of this required new generation capacity. Notable examples of this trend are the firm long-term exports from Manitoba to Minnesota, and from Quebec to New York and Vermont. In order to provide a realistic outlook of export transactions, we have included estimates of export sales based on potential transactions, some of which are not yet confirmed, and for which the NEB has not granted authorization. This is essential if we are to provide a realistic estimate, as most existing export licences terminate within the study period. However, this assumption is without prejudice to future NEB decisions on specific applications. A detailed discussion of these assumptions is contained in section 5.2.

Interprovincial transactions of electricity have taken place for many years to take advantage of the benefits which can be gained by interconnecting systems: reserve sharing, improved reliability and economy exchanges for example. Our projections include ongoing interprovincial trade, for example between Newfoundland and Quebec, Quebec and New Brunswick, New Brunswick and Prince Edward Island, and Alberta and British Columbia.

5.1 Domestic Electricity Demand

The Canadian electric power industry has grown rapidly from small hydro plants serving isolated loads in the early 1900s to today's vast interconnected electric power networks with total installed generating capacity in excess of 95 000 megawatts[1] from a variety of generating sources.

After several decades of growth in electricity demand at annual rates of about 7 percent, demand growth fell steadily from the mid-1970s until very recently, as a result of the slowdown in economic growth and conservation and efficiency improvement measures which accompanied the oil price shocks of the 1970s. By the late 1970s, annual electricity demand growth rates averaged close to 3 percent. Growth resumed strongly over 1982-1989 averaging about 4.6 percent per year, with recovery from the 1982 recession. In 1989 electricity demand in Canada increased by 2.3 percent from 1988 levels. In some regions growth rates have exceeded this level in recent years; in Ontario, energy demand increased by 4.2 percent in 1989 over 1988.

Table 5-1 contains our electricity demand outlooks (discussed in Chapter 4) expressed in terawatt hours.

Table 5-1 also contains our projections of the annual peak power demand (i.e. the highest level of power demanded in the year) for each province and region. These have been calculated from the energy demand outlooks of Chapter 4 by projecting utility load factors (the ratio of average to peak load) based on historical data and on our expectations with regard to peak load management by utilities. At present, load factors typically range between 60 and 75 percent. We assume that in most provinces, efforts to shift consumption from peak to off-peak times (load shifting management) will cause load factors to gradually increase by as much as 3 percentage points in some provinces over the study period.

The projections in Table 5-1 also take into account the effects of increasing amounts of demand management whereby provincial

1 The units most commonly used for electrical energy and power (i.e. the capacity used to produce electricity) are multiples of kilowatt hours (kW.h) and kilowatts (kW) respectively. The multiples of these units used in this report are gigawatt hours (GW.h), terawatt hours (TW.h), megawatts (MW) and gigawatts (GW). (See Appendix Table A1-1).

Table 5-1

Domestic Electricity Demand by Province [a]

Electrical Energy Demand

	Energy Demand (Gigawatt hours) [c] 1989	2010	Rate of Growth (percent/year) 1989 to 2010
	(1)	(2)	(3)
Newfoundland	10676	15806	1.9
Prince Edward Island	728	1126	2.1
Nova Scotia	9050	12257	1.5
New Brunswick	13566	18732	1.6
Quebec	163524	226392	1.6
Ontario	147492	202822	1.5
Manitoba	17638	21699	1.0
Saskatchewan	13625	15459	0.6
Alberta	41176	55644	1.4
British Columbia	55912	74308	1.4
Yukon	440	566	1.2
Northwest Territories	559	775	1.6
Total Canada	**474386**	**645586**	**1.5**

Peak Demand [b]

	Peak Demand (megawatts) 1989	2010	Rate of Growth (percent/year) 1989 to 2010
	(4)	(5)	(6)
Newfoundland	1981	3148	2.2
Prince Edward Island	134	191	1.7
Nova Scotia	1696	2172	1.2
New Brunswick	2439	3284	1.4
Quebec	29606	39681	1.4
Ontario	25315	32012	1.1
Manitoba	3429	4075	0.8
Saskatchewan	2503	2735	0.4
Alberta	5816	8157	1.6
British Columbia	9386	11534	1.0
Yukon	79	111	1.6
Northwest Territories	105	157	1.9
Total Canada	**82489**	**107257**	**1.3**

Notes: The numbers in this table have been rounded.
[a] Excludes export sales.
[b] Peak Demand is the sum of non-coincident peak loads in each service area and therefore overstates the actual peak.
[c] Converted from petajoule values in section 4.1 using conversion factor of 3.6 petajoules per terawatt hour.

utilities provide incentives to their customers to promote the efficient use of electricity by encouraging the use of more efficient appliances, motors, lights and equipment and the implementation of higher building insulation standards.

We project growth in electricity demand in Canada at an average annual rate of 1.5 percent from 1989 to 2010. The provincial growth rates in the Control Case are very comparable to the growth rates for electricity demand in the 1988 Low Case. This reflects similar assumptions about economic activity in the two cases.

The specific assumptions which lead to the Control Case provincial electricity demand projections are discussed in Chapter 4. The following discussion compares the Control Case outlook for individual provinces with the views of the provincial utilities. Individual provincial utilities typically publish long-run projections of electricity demand which are used as the basis for their generation expansion programmes. As the demand for electricity is a derived demand, from electricity-using equipment, all projections must start with certain assumptions which influence demand for electricity. These differ by organization. To the extent that these assumptions differ, so too will the outlook for electricity demand. To the degree possible, and where there is public information available, the following discussion compares our Control Case outlook for individual provinces with the published utility view. We do not have a published forecast from Manitoba Hydro.

For the provinces of Quebec and Ontario, our Control Case projections fall in the range of the utilities' high and low cases. For

Newfoundland and Prince Edward Island, the Control Case electricity demand levels are similar to the respective utility's forecasts.

New Brunswick Power[1] indicated that it expected provincial electricity demand to increase at an average annual rate of 2.8 percent to the year 2005. This is almost twice the rate of increase projected in our Control Case. There are several major differences between the projections. In the New Brunswick Power outlook, real gross domestic product in the province grows at 2.4 percent per year from 1990 to 2005. In our Control Case, economic growth is below 2 percent per year. New Brunswick Power shows commercial and industrial electricity demand growing more rapidly than each sector's GDP, while in our Control Case we incorporate efficiency improvements which tend to offset increased penetration of electrotechnologies and plug load. In the residential sector, New Brunswick Power indicates annual real personal disposable income growth per capita considerably higher than in our Control Case. The Control Case also includes large efficiency improvements for appliances, while it is not clear that New Brunswick Power's outlook is as optimistic in this area.

Electricity demand growth for Nova Scotia in our Control Case is, in many respects, similar to Nova Scotia Power's low case[2], which has net system requirement growth of 1.4 percent per year, over the next ten years, compared to their base case view of 3.4 percent. Real personal disposable income in their base case grows considerably higher than in our Control Case. Their base case real provincial output increases at 1.5 percent per year, compared to 1.8 percent in our Control Case. Nova Scotia Power's outlook for domestic customer additions is for annual growth of 1.4 percent per year, while household growth in our Control Case is 1.0 percent. Our Control Case would appear to incorporate greater efficiency improvements, particularly for residential customers. While Nova Scotia Power includes penetration of more efficient appliances in its outlook, it does not appear to include the same level of improvement in efficiency as that in our Control Case. Similarly, for the commercial and industrial sectors, our Control Case would appear to include more efficiency measures which would offset increased penetration of electricity-using applications.

Our Control Case outlook for electricity demand growth in Saskatchewan, at 0.6 percent per year, is much lower than the Saskatchewan Power projection of 2.0 percent per year from 1989 to 2010. There is not sufficient information available to compare the assumptions of the utility's outlook to the Control Case. Our Control Case projections of growth in real Gross Domestic Product and of household formation average 1.4 and 0.7 percent per year, respectively from 1989 to 2010. Commercial sector real GDP grows at 1.4 percent on average and industrial real GDP at 1.3 percent per year. In our projection, energy intensity in the commercial sector declines at 0.7 percent per year and industrial intensity at 0.4 percent. These rates are both slower than the national average declines in intensity for these two sectors. With the introduction of the efficiency measures discussed in Chapter 4, household energy use declines at the rate of 0.5 percent per year, also somewhat more slowly than the national average. It is the assumption of efficiency gains combined with slow economic and household formation growth that result in the Control Case projection, and lead to a delayed expansion plan relative to that of the utility (see below).

Our Control Case projection of Alberta's electricity demand is also lower than that of the Alberta utilities. In making a general comparison, we note that the Electric Utility Planning Council (EUPC), in its most recent outlook[3], developed two cases, a high case with some conservation and a low case with less. Our Control Case economic outlook is similar to the EUPC low case, while the conservation and efficiency assumptions are closer to those of the EUPC high case. The result is a projection which is below the EUPC low case, and leads to a lag in our Control Case expansion programme relative to that of the utilities.

B. C. Hydro's projected electricity demand[4] growth is above that of our Control Case, as their projection of real GDP exceeds the Control Case over the first ten years of the outlook by over 0.5 percent per year, and their population growth and household formation are somewhat higher as well. In comparing our Control Case electricity demand with that of B.C. Hydro, while we reduce

1 New Brunswick Power, *Fifteen Year Load Forecast, 1990-2005*, November 1990

2 Nova Scotia Power Corporation, *Load Forecast Report 1990*, System Planning Division, External Assessments and Forecasts, September 1990

3 1990 EUPC Electric Forecast Working Range for Planning Resource Additions 1990-2005, prepared by EUPC Forecast Task Force August 1990)

4 B.C. Hydro, *An Introduction to the 1990 Electricity Plan*, April 1990

demand to reflect the impact of demand side management programmes, B.C. Hydro estimates demand exclusive of these programmes, and counts the demand reductions of these programmes as part of supply. In other words, part of the difference between our Control Case demand and B.C. Hydro's forecast is that ours is net of demand management, theirs is gross.

These comparisons illustrate the uncertainties in projecting energy and electricity demand and resultant generation requirements. For each assumption required there is a range of values which most analysts would agree to be "reasonable". It is not only differences in individual assumptions which result in different projections, but as much the way in which the assumptions are combined, for example, the comparison for Alberta where we are more optimistic about conservation and efficiency improvements in a low economic growth environment than is the EUPC.

5.2 International and Interprovincial Trade

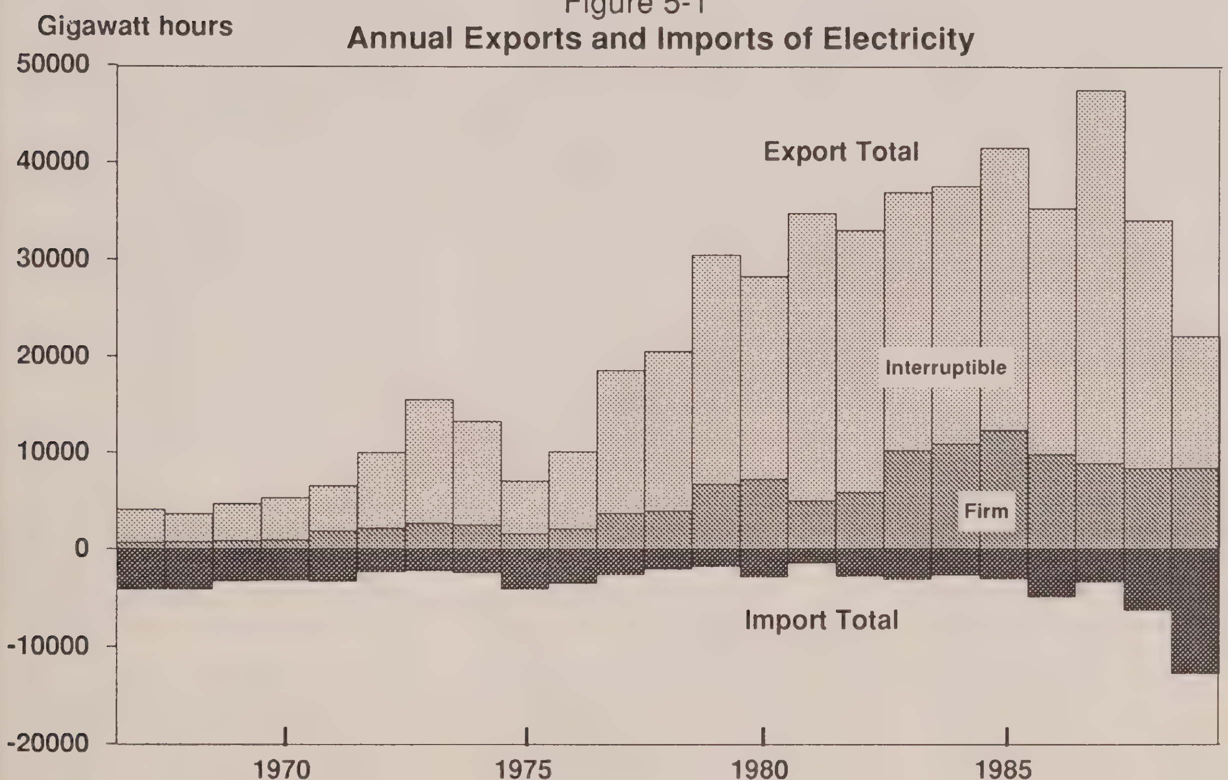
In Canada, provincial transmission networks were initially developed in isolation of one another, with the exception of Ontario, which established international power lines in the early 1900s. As opportunities arose, interties between neighbouring systems were established, initially along north-south lines and later between provinces, to gain improved reliability and cost reduction in system operations.

Up to the early 1970s, exports and imports were approximately in balance. However, by the mid-1970s several generating plants which had been committed before 1973 in response to expected high load growth rates were completed. When these high growth rates did not materialize, substantial quantities of surplus capacity were made available, much of it hydro- and coal-based. This surplus found a ready market in the U.S. given the rapidly increasing cost of oil-based generation.

Figure 5-1 shows the evolution of international trade in electricity since 1970.

Gross exports increased from 10.4 terawatt hours in 1972 to about 47 terawatt hours in 1987. From 1987 onward there has been

Figure 5-1
Annual Exports and Imports of Electricity



a significant decline in export sales; in 1990 gross exports were 16.5 terawatt hours while imports were 16.2 terawatt hours, resulting in net exports of only 0.3 terawatt hours. Thermal generation restrictions in Ontario, low water conditions in 1989 and 1990 in Manitoba, Quebec and Newfoundland-Labrador, and higher than expected domestic demand have reduced the surplus electricity available for exports. Moreover, difficulties encountered at some Ontario nuclear power plants, acid gas emission limits placed on Ontario coal power plants, and very low water conditions at Quebec and Labrador hydroelectric generating stations have forced Ontario and Quebec to import large quantities of electricity from the U.S. during the last two years. We expect these conditions to be temporary, and assume that Canada will resume its role as a net exporter of electrical energy in the coming years.

U.S. utilities have used firm exports from Canada (about 48 percent of total Canadian gross exports in 1990) to postpone investment in new plants, and to provide reserve capacity and emergency support. Electricity generation has environmental impacts in both countries and these impacts are a consideration in assessing the potential benefits of export trade.

Most of Canada's exported electricity comes from hydro or nuclear sources which produce relatively little atmospheric emissions. Quebec, Manitoba and British Columbia export mainly hydroelectricity, and New Brunswick nuclear electricity. The exported energy replaces fossil fuel-fired generation in the U.S., thereby reducing air pollutant emissions and associated problems such as acidic deposition and diminished air quality. In the past, only Ontario has been a major exporter of energy produced by burning fossil fuels (mainly coal). This energy was used in the U.S. market to displace electricity generated by older fossil fuel-fired plants; the incremental acid gas emissions produced in Ontario were slightly more than offset by reductions in the U.S. Recently, Ontario's domestic requirements have increased more than anticipated and unexpected difficulties have been encountered at some nuclear power plants. Stringent acid gas criteria set by the province have caused restrictions on thermal generation. Ontario has therefore become an importer of electricity. Since these electricity imports are generated mostly from U.S. fossil fuel power plants, the net effect on the aggregate gas emissions in the region has recently increased relative to what would have occurred had Ontario's nuclear plants performed as expected.

Regional American Markets

Electricity trade patterns between North American utilities have evolved on a regional basis. Each region corresponds to an aggregation of utilities which are tightly interconnected. This regional structure is reflected in the North American Electric Reliability Council (NERC) and its member regions. In the regional councils of NERC, Canadian utilities join with those in the U.S. to promote reliable power supply and to coordinate standards of planning and operation.

From the perspective of exporting Canadian utilities, the U.S. market comprises five distinct areas. These are illustrated in Figure 5-2, which also shows the interconnection capacity with those markets in 1990.[1] New Brunswick exports to New England; Quebec to both New York and New England; Ontario to the Michigan-Ohio Valley area and New York; Manitoba to Minnesota and North Dakota; Saskatchewan to North Dakota; and British Columbia to Washington, Oregon and California. At the present time there are no direct exports from Alberta, Nova Scotia, Newfoundland and Prince Edward Island.

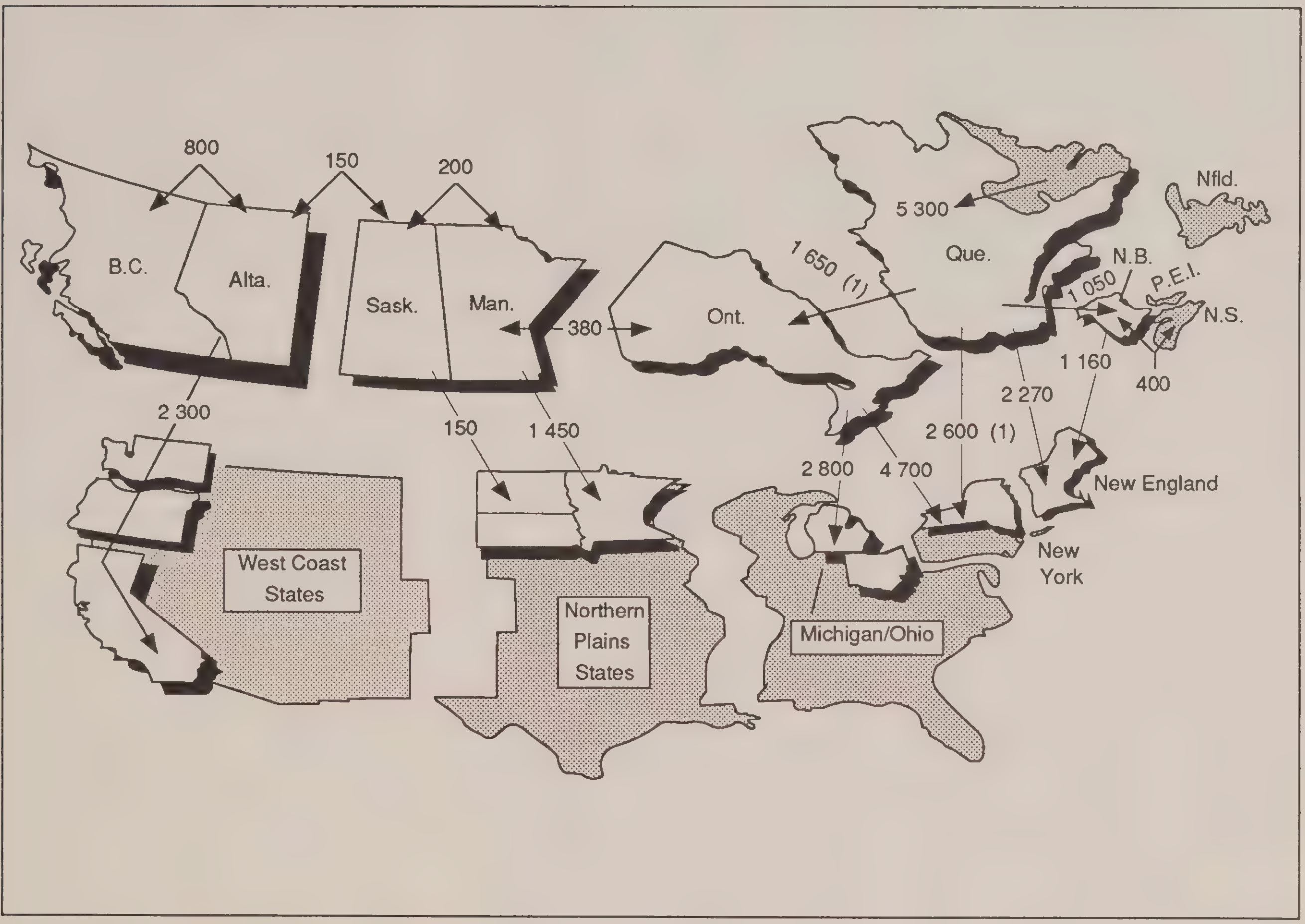
Canadian and U.S. utilities face similar difficulties in planning for future needs. Conservation trends are causing great uncertainty in forecasts of future demand. Recent and pending legislation to decrease acid gas emissions affect both installed generating capabilities as well as new supply options. The growing concern with greenhouse gas emissions, discussed further in Chapter 11, must also be considered in any expansion plan.

New England is served by many relatively small utilities. The region consists of six states, each with its own regulatory commission. The result is that building major new capacity additions or transmission lines is complicated, often requiring inter-utility, interstate, and regulatory co-ordination. This is facilitated by pooling arrangements and a co-operative approach to solving supply problems. The region has limited indigenous resources for power generation and is heavily reliant on coal, uranium, and particularly oil, because of the latter's convenience and historic availability at low cost. However, coal use is subject to increasingly stringent environmental constraints, nuclear plants have met with widespread public opposition, and the cost of oil-based

1 The interconnection capacity is an approximate value only. The actual capacity varies continually with system conditions.

Figure 5-2

Canadian Exporting Regions and United States Export Markets, Approximate Interconnection Capacity (2) 1990



Notes: (1) Simultaneous transfer capacity to Ontario and U.S. is 3 300 MW.

(2) Interconnection capacity is dependent on the state of the interconnected systems at any given time and varies continually. For this reason an approximate value is shown.

generation varies with the world oil price.

Utilities had been planning for modest load increases, but New England's load has been growing more quickly than anticipated over the past several years. Growth has almost stopped as a result of the recent recession, which has been particularly severe in New England, but is expected to resume again in the near future. Many existing generating plants are small and are reaching the end of their design lives. However, because of an uncertain regulatory climate, many U.S. utilities are reluctant to commit themselves to building major new generating plants, as they are expensive capital projects with long lead times. Partly as a result, during the period of rapid growth in the late 1980s, some areas of New England experienced capacity reserve shortfalls and even brownouts in the summer peak period. Utilities in New England have increasingly sought new methods of supplying their customers' loads. Conservation through demand management programs has become substantial throughout the region, and there has been increased willingness to consider long-term firm purchases from other U.S. suppliers and Canadian utilities. With the prospect of increased flow of natural gas either from Canada or the U.S. to this northeast market, there has been increasing interest in combined cycle or co-generation plants developed by non-utility suppliers to serve part of the utilities' forecast demand. Advantages offered by industrial co-generators and independent power producers include generating capacity with short construction lead times, relatively low capital costs, and smaller environmental impacts per unit of energy production compared to coal-fired steam capacity.

The New York market, like that of New England, is served by numerous utilities. Although some of them serve large loads, most serve small areas. As a result, New York shares some of New England's problems of market fragmentation and difficulties in building transmission lines and generating plants. Although both areas have pooling arrangements to co-ordinate system operating and planning practices, New York, unlike New England, has a large state-owned utility, the New York Power Authority, which controls the bulk transmission network and which is directly interconnected with Quebec. As a result, the New York Power Authority has been the principal purchaser of Quebec's exports to New York, acting on behalf of the several utilities in the state. This arrangement has worked effectively, enabling New York to take advantage of opportunities for electricity trade.

Although it is in a better supply position than New England, New York is nonetheless heavily reliant on older oil- and coal-fired plants and will need additional sources of supply in the mid- to late-1990s. Utilities in New York are also reluctant to commit to the construction of major new generating plants and have looked to long-term purchases from neighbouring U.S. and Canadian utilities, such as Hydro-Québec, as a secure and economic future source of supply.

Michigan and Ohio have excess capacity at the present time, and will not likely require substantial amounts of capacity until late in the 1990s. Abundant reserves of local coal provide an economical and reliable future supply of fuel. Some ninety percent of this area's electricity requirements are currently being met by coal-fired generation. The recent passage of the U.S. Clean Air Act, with its major thrust toward reducing acid gas emissions, will have an effect on the generation plans for this region. New coal-burning technologies such as fluidized bed boilers, integrated gasification combined cycle (IGCC), and improved environmental control equipment are expected to be implemented in order to ensure that coal power plants are able to operate in the future in an environmentally acceptable manner and with competitive generation costs.

The Minnesota, North Dakota and South Dakota region is not likely to need much new capacity until the late-1990s and is presently well supplied from coal-burning plants which have access to an abundant, low-cost, lignite resource. U.S. utilities' access to this resource reduces the attractiveness of purchasing Manitoba's electricity, as the economies to be gained from trade are more modest than in other market regions where the alternatives for the U.S. utilities are more costly and the needs more pressing.

Washington, Oregon and California constitute the potential export market for British Columbia and Alberta; the largest of these markets is southern California. California utilities, while not likely to need major new capacity additions until the mid- to late-1990s, are heavily dependent on a large number of small gas- and oil-fired generating stations and on privately owned generating units, many of which are gas-fired.

Utilities in southern California face stringent environmental regulations and a burgeoning independent power-producing sector which is increasingly able to supply the region's growing loads. As well, issues such as security of supply

for a system dependent on premium fuels and reliability of supply from the large number of non-utility participants, place additional burdens on utility planners. As a result, utilities are averse to making major capital investments in new plants. While Western Canadian utilities may wish to supply more to this growing market, in the past their access to the long and heavily loaded north-south electric transmission lines belonging to the U.S. agency Bonneville Power Administration (BPA) was restricted. BPA had given preferred access to its own surpluses and to those of neighboring U.S. utilities in the Pacific Northwest region, thus precluding British Columbia Hydro (B.C. Hydro) from making long-term firm exports. Under the Free Trade Agreement (FTA), U.S. utilities in the Pacific Northwest region and B.C. Hydro are granted the same priority status.

American Regulatory Environment for Canadian Exports

Imports of Canadian electricity and construction of international power lines may be affected by U.S. federal and state regulatory authorities.

- The Economic Regulatory Agency (ERA) of the Department of Energy administers the issuance of presidential permits for the construction and operation of international power lines. A permit must be sought for any change in use or operation of an international power line. This, in effect, gives the ERA broad control over electricity imports.

  A presidential permit requires the concurrence of the Secretary of State with respect to the trade implications and of the Secretary of Defence regarding any national security implications. As well, if a project has the potential to cause substantial changes to the environment, an Environmental Impact Statement may be required.

- The Federal Energy Regulation Commission (FERC) regulates:

  - rates charged by investor-owned utilities for interstate resale of electricity including imported electricity;
  - rates for transmission services used in interstate electricity trade; and
  - rates charged by federal power marketing bodies, such as the Bonneville Power Administration, for the sale of capacity, energy, and transmission services.

- State regulatory boards have a mandate to minimize the cost of service to consumers, while setting fair rates of return on capital for utilities. As a result they can (and have) effectively limit or deny the imports of Canadian energy or affect their marketability through the rates they set and through their determination of the extent to which the U.S. importing utility may recover payments to the Canadian exporter.

Regulation of the U.S. electric power industry is currently being re-examined on the premise that a more competitive market structure would be conducive to increasing supply at least cost to the consumer. New business practices, such as sales to utilities by non-utility power producers, competitive bidding for supply to utilities, and more open access to transmission networks, are being implemented in order to create a more competitive supply environment. FERC issued Notices of Proposed Rulemaking (NOPR) in March, 1988 which solicited comments on proposals to introduce a competitive bidding process for incremental supplies of electricity and to streamline the regulation of independent power producers. FERC has yet to act on these NOPRs, preferring to act on a case by case basis. In addition several State Public Utility Commissions have undertaken their own competitive bidding schemes. This will impact on the way U.S. and Canadian utilities negotiate export arrangements in the future. In the last few years, several U.S. utilities have been subjected to state regulatory reviews of the prudency of capital investments in facilities made to serve anticipated customer loads. In some instances, major investments have been deemed imprudent and the utilities have not been allowed to earn a return on some or all of their investment. Other aspects of regulation pose difficulties for U.S. utilities, particularly in the areas of the environment, of nuclear plant licensing, of the acquisition of rights-of-way for major new transmission lines, and of the siting of new generating plants.

As a result of these pressures, U.S. utilities face a period of heightened uncertainty and a proliferation of potential alternative supply options. U.S. investor-owned utilities are therefore looking more and more to purchases from neighbouring U.S. and Canadian utilities as well as independent power producers as secure and reliable sources of supply to satisfy their customers' needs. While this situation may offer new export opportunities for Canadian utilities, they will have to

compete in a rapidly changing market.

5.2.1 Firm Exports

Up to 1989, most electricity exports were on an interruptible basis. The most notable feature of our export projections is the shift in emphasis to firm energy contracts, as the present surplus generating capacity in some Canadian utilities is being absorbed by increased domestic demand, and as U.S. utilities are looking for more secure and reliable sources of supply to satisfy their customers' needs. Firm exports are those which affect utilities' expansion programs. The projections of firm exports are discussed below for each exporting province. The projections of interruptible exports are discussed in section 5.4.

New Brunswick

New Brunswick and New England have a long history of mutually advantageous trade. While the size of interconnections is not very substantial, the trade has evolved through joint construction of large plants enabling the region's utilities, including those in New Brunswick, to avail themselves of economies of scale, to share reserves, to make economy transactions[1] and to realize other interconnection benefits.

Since the early 1970s, New Brunswick has had access to substantial quantities of surplus hydroelectricity from Quebec. New Brunswick, through special contractual arrangements with Quebec, sells some of this energy, along with a portion of its own oil-fired and nuclear generation, to the export market. New Brunswick has sold part of the Point Lepreau nuclear plant's production on a unit participation basis. As a result, export trade has increased substantially. Firm sales of nuclear capacity and energy and an active trade in interruptible energy have reduced New England's dependence on oil-fired generation as well as displacing some coal.

The present outlook for exports is less optimistic than has been projected in recent years, as projections of New England demand for electricity have declined. Based on discussion with New Brunswick Power, we are assuming that New Brunswick will renegotiate the existing Point Lepreau 1 export contract and continue exporting 230 megawatts to New England in the 1991 to 1994 period. After that, New Brunswick will continue exports of 200 megawatts and 1489 gigawatt hours per year to New England over the remainder of the study period. We also assume that two small export agreements will be extended to 2010.

Quebec

Quebec found itself, like other utilities, with a substantial excess supply of capacity and energy in the late 1970s when the expected loads failed to materialize. With a limited ability either to sell surplus energy in-province or to transmit it to other utilities[2] at that time, Quebec spilled large quantities of impounded water for a period without producing energy.

This situation prompted Quebec to discount bulk sales to certain domestic industrial users in order to promote higher electricity use, to embark on the construction and upgrading of several major interconnections with Ontario, New Brunswick, New York and New England, and to invest considerably in enhancing its network reliability. The technical problems of interconnection have been partially resolved through the use of high-voltage direct-current transmission lines.[3] Quebec has, in recent years, been marketing long-term firm sales to its neighbors and is willing to prebuild new plants for that purpose.

Throughout the 1970s and into the early 1980s, Quebec used its interconnections to export interruptible energy to the U.S. and neighbouring Canadian markets, where it was used mainly to displace generation from more expensive oil and coal. In the early 1980s the demand in the U.S. for more of Quebec's surplus hydro energy than could be delivered using the existing interconnections meant that new lines had to be built. As a result, contracts were concluded with New England and New York for scheduled deliveries of firm energy. This provided a financial basis for investments in major new interconnections.

In the last few years, both New England and New York have been actively looking for new sources of supply. Consequently, Quebec's exports are increasingly of long-term firm power and energy, designed to allow the U.S. utilities to defer construction of new plants and to reduce the need for fossil fuel. Quebec has concluded export agreements with New York and New England totalling about

1 Energy sold by one power system to another to effect a saving in the cost of generation when the receiving party has adequate capability to supply the loads on its own system.

2 For technical reasons Quebec cannot operate its system synchronously with neighbouring ones; it has thus been operated in isolation.

3 High-Voltage Direct-Current interconnections allow two systems to exchange energy even though the systems are not synchronized.

2250 megawatts with deliveries to start in the mid-1990s. Consistent with its published marketing objectives we are assuming that Quebec will make firm exports of about 3550 megawatts by the year 2006.[1] The following major exports are included in our projections:

- 800 megawatts, 3000 gigawatt hours per year summer export to New York State for the study period;
- two blocks, of 500 megawatts and 3300 gigawatt hours per year each, to New York State, beginning in 1995 and 1997;
- up to 450 megawatts and 2957 gigawatt hours per year to Vermont, beginning in 1995; and
- an additional firm export, to an as yet unspecified customer, of 1250 megawatts and 8200 gigawatt hours per year beginning in the year 2002.

Ontario

Ontario was, until recently, Canada's largest exporter of electricity. Its trade continues to be primarily in interruptible energy based on close coordination of exchanges with U.S. utilities in New York, Michigan and Ohio; however, it has made firm exports from time to time as opportunities arose. Although most of Ontario's exportable surplus energy is coal-based, its extensive reliance on nuclear generation and access to indigenous and purchased hydroelectricity give it operational flexibility. Through close coordination with neighbouring U.S. utilities, Ontario can tailor its exports to cover a wide range of individual market requirements, including firm capacity and energy for short or long periods.

We have assumed that Ontario will not conclude major new firm export contracts when the present firm export of 45 MW to Vermont ends in 1992. Although the United States market may offer renewed opportunities for exports in the mid- to late-1990s, Ontario will not at that time have substantial surplus capacity.

Manitoba and Saskatchewan

Since the early 1970s, Manitoba has been exporting substantial amounts of hydro-based electricity. The province has substantial undeveloped hydroelectric potential which it would like to develop for sale to the U.S. and to neighbouring Canadian utilities.

Although Manitoba has faced strong competitive pressures in its export markets, it has been successful in negotiating a long-term firm export to Minnesota and is pursuing other potential sales. Manitoba Hydro has advanced the completion of the 1200 megawatt Limestone plant to 1991 to supply a firm export contract of 200 megawatt and 883 gigawatt hours per year firm export between 1993 and 1996 to a Minnesota utility. An additional firm export of up to 500 megawatts and 4380 gigawatt hours per year is scheduled to begin in 1993 and end in 2005. We estimate that Manitoba will renegotiate the 500 MW contract for the remainder of the study period. The Minnesota and North Dakota markets are summer peaking systems, unlike that of Manitoba, which is winter peaking. This diversity of capacity requirements provides ongoing opportunities for seasonal transactions; Manitoba recently announced a new seasonal export agreement which will provide it with 500 megawatts of additional winter peaking capacity starting in the mid-1990s in return for providing its U.S. partners with a similar service in the summer season.

Saskatchewan exports small amounts of energy (diversity exchange) to North Dakota; this is expected to continue.

Alberta and British Columbia

While Alberta is not a direct exporter of electricity at present, it has been coordinating its coal-based generation more closely with British Columbia whose generation is primarily hydroelectric. Since 1986, through an interconnection with Alberta, British Columbia has had access to Alberta's coal-based generating resources. The combination of hydro and coal generation permits British Columbia to better capitalize on export opportunities by complementing its variable hydro supply with reliable thermal generation from Alberta.[2] We have not included any firm export sales from Alberta in our projections.

As for firm exports from British Columbia, we have assumed that the third north-south transmission line between the U.S. Northwest and California scheduled for completion in 1992, will allow increased sales to take place. With the creation of Powerex[3], the institu-

1 Hydro Quebec Development Plan 1990-1992, Horizon 1999.

2 British Columbia has large surplus hydroelectric capacity, but because of limited reservoir storage capacity, its energy producing capability is very dependant on precipitation. While at peak times Alberta needs most of its own capacity, at other times it has excess reliable coal-based energy capability. Alberta is therefore an ideal complement to the seasonal and annual variability of British Columbia's hydroelectric system.

3 Powerex is a marketing operation, set up by B.C. Hydro, to serve short- and long-term bulk electricity markets in and outside British Columbia, including Alberta and the Western U.S. The organization acts as a power broker between sellers and buyers - both utilities and non-utility generators - using the B.C. Hydro system to store and transmit electricity.

tional framework is now in place for energy produced by public or privately owned companies in British Columbia to be exported to the United States. The agency may also market coal-generated electricity which Alberta could supply.

As a result of these measures, and based on discussion with Powerex and B.C. Hydro, we have assumed that British Columbia will make a total of about 850 megawatts of firm exports to utilities in the U.S. north-west and California beginning in the mid-1990s. This amount may increase later due to the return of the Downstream Columbia River Benefits[1] to British Columbia in 1998. The utility will gain up to 1100 megawatts from this. The following major exports are included in our projections:

- up to 200 megawatts, 1400 gigawatt hours per year to California from 1990 to 2010;
- another 300 megawatts, 2100 gigawatt hours per year to California to begin in 1995; and
- 350 megawatts, 2500 gigawatt hours per year to Washington State from 1995 to 2010.

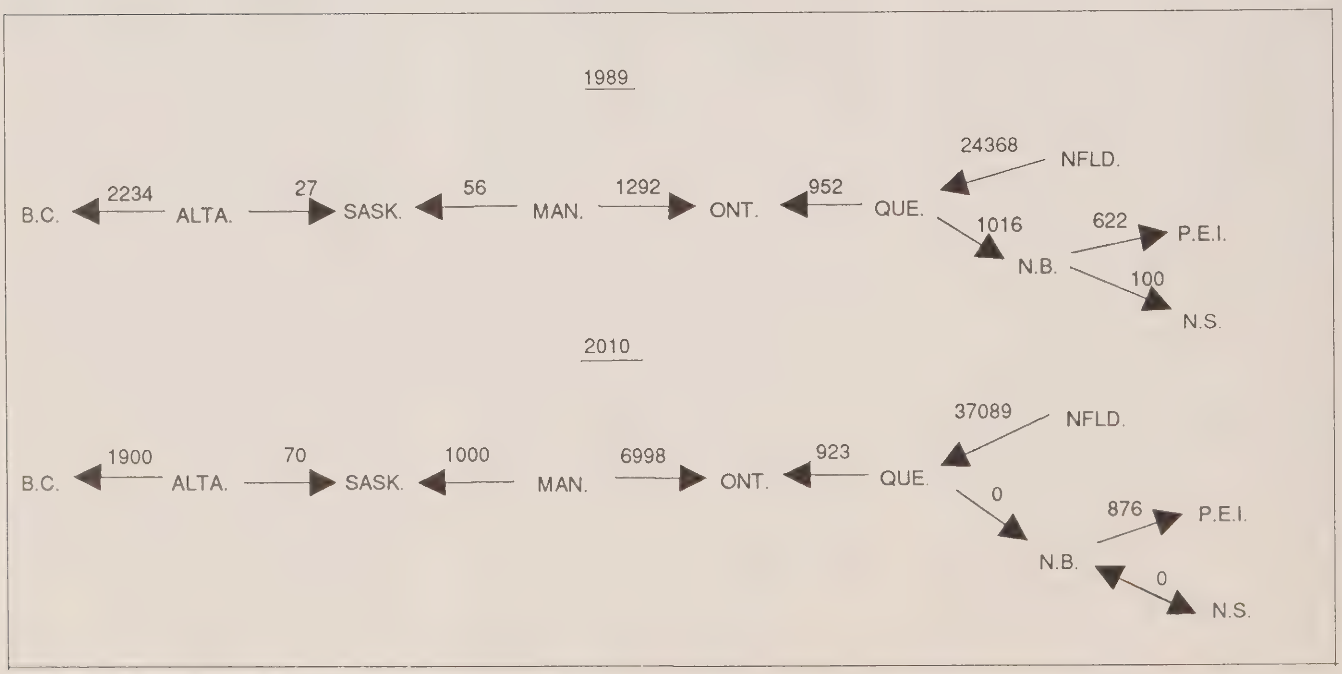
5.2.2 Firm Interprovincial Trade

Most Canadian utilities are interconnected interprovincially as well as internationally. The conditions which make international trade possible also apply to interprovincial trade. As for firm exports, firm interprovincial trade also affects utilities' expansion programs. Interruptible interprovincial trade is discussed in section 5.4.

With respect to firm interprovincial trade, provinces such as Ontario and Saskatchewan which rely on fossil fuels and are adjacent to major hydro utilities could opt to purchase capacity, rather than to build their own plants, if the resultant economic and other benefits are attractive enough. The 1000 MW

1 In 1966 Canada and the United States signed the Columbia River Treaty, whereby the benefits of electricity generated from U.S. hydroelectric plants, from water stored behind Canadian dams on the Columbia River, were sold to the U.S. for a period of 30 years.

Figure 5-3
Net Interprovincial Electricity Trade
Gigawatt hours



sale by Manitoba to Ontario is an example of this type of transaction. However, provinces with predominantly hydraulic resources are typically interconnected to the export market where the opportunities for electricity sales have been more lucrative than interprovincial trade because of the higher cost in the U.S. of alternative supplies of electricity.

Based on discussions with provincial utilities we have included the following firm transactions between provinces (Figure 5-3):

- the sale to Quebec of 4700 megawatts, 31 085 gigawatt hours, from Churchill Falls in Labrador, between 1990 and 1998, decreasing to 4530 megawatts, 29 745 gigawatt hours beginning in 1999 due to a recall of 170 megawatts from Newfoundland;
- sales from New Brunswick to Prince Edward Island as follows: a small firm unit participation sale of 20 megawatts, 142 gigawatt hours from the existing Dalhousie 2 power plant for the study period, another sale of 50 megawatts, 366 gigawatt hours between 1988 and 1994, and a further sale of 30 megawatts, 148 gigawatt hours from the Belledune power plant yet to be constructed;
- up to 400 megawatts of peaking capacity purchased by Quebec from New Brunswick between 1991 and 2010 from gas turbine units built expressly for that reason; and
- up to 1000 megawatts, 5700 gigawatt hours long-term firm sale by Manitoba to Ontario from the Conawapa hydro plant, between 1998 and 2010.

5.3 Generating Capacity and Electrical Energy Production by Region

Electricity demand changes continually, following patterns which recur daily, weekly, seasonally and annually. In Canada, the annual peak demand usually occurs in December or January. Electricity producers require sufficient generating capacity to meet this peak demand. Sound engineering practice also requires that utilities maintain enough reserve generating capacity in order to provide for reliable and continuous service to customers even during equipment breakdowns or maintenance. Some utilities require a larger reserve margin than others, depending on individual equipment characteristics and operating conditions.

Electricity generating units vary in design capacity[1] and in the resource they exploit; specific units are used for different demand-meeting purposes. Larger, newer facilities using more economical energy resources such as coal, uranium and hydro are used as much as possible. These so-called base load units often operate in excess of 80 percent of the time and are characterized by high initial capital costs and low operating costs. At the other extreme are facilities called "peaking" units which operate for very short periods - often less than 5 percent of the time. These are typically older or smaller units which consume premium fuels or are hydro units which have limited reservoir storage capacity. Oil- and gas-fired peaking units are generally less expensive to build for the same capacity than base load units, but are more expensive to operate.

Over and above utility-supplied generation to meet customer demands, most provincial governments have developed policies to encourage development of electrical generating facilities by independent power producers (IPPs) to serve at least a portion of the provinces' supply requirements. Companies and individuals are increasingly showing interest in producing electricity for their own use and/or for sale to utilities. Such projects may include cogeneration, combined cycle natural gas-fired generation (such as the recently concluded contract between TransAlta Resources and Ontario Hydro), small hydro sites, and municipal waste generation as well as a whole range of renewable technologies such as wind and solar.

Finally some electricity is produced in industries which use by-products of their production processes as fuels to provide thermal energy for industrial processes and to cogenerate electricity. Examples are pulp and paper, petrochemical, and aluminium companies. Electricity surplus to the requirements of those industries may be sold from time to time to electric utilities to augment their own supplies.

In 1989, non-utility generation accounted for 39.7 terawatt hours, about 8 percent of the total electricity production in Canada. By 2010, we project that about 63.6 terawatt hours, just under 10 percent of the total, will come from non-utility sources.

Provincial Projections

Provincial utilities generally expand their electric power systems to

1 The units are rated by the amount of electricity they can produce per unit of time. For example, a 100 megawatt unit can produce 100 megawatt hours of electricity per hour of operation.

supply reliable power, respecting all relevant environmental regulations, at least long-term cost to ratepayers in order to meet the forecast firm electricity demand and firm export and interprovincial contracts. The provincial electricity supply alternatives we have developed are designed to meet the projected provincial demands we outlined in Chapter 4 and the firm export and interprovincial contracts discussed in section 5.2.1 and 5.2.2. We recognize that to the extent our projections are different from those of the provincial utilities, the timing of generating capacity additions would also differ. The sequence and/or choice of generating capacity additions we have included, however, are generally similar to those planned by the utilities as provided in discussions and consultations with utility representatives.

To produce electricity, each province exploits those resources which are the most economical to it. Alberta, Saskatchewan and Nova Scotia, for example, base their electricity production on plentiful coal reserves, while British Columbia, Manitoba and Quebec rely almost exclusively on abundant hydro resources. The other regions of Canada rely to varying degrees on a mix of indigenous and purchased energy sources. For this reason, each province and territory is dealt with separately in this section in which we describe the resources that we project will be used to meet in-province demands and firm interprovincial and export sales.

Table 5-2 shows the relative magnitude of the various provinces' generating capacity and actual energy generation for the year 1989, the latest year for which complete statistics are available. The Newfoundland and Labrador statistics include existing long-term firm sales to Quebec from the Churchill Falls generating plant.

Table 5-2

Generating Capacity and Energy Production by Province and Territory -1989

	Capacity [a]		Energy	
	Megawatts	Percent	Gigawatt Hours	Percent
Newfoundland	7014	7.2	35044	7.2
Prince Edward Island	112	0.1	106	0.0
Nova Scotia	2151	2.2	8950	1.9
New Brunswick	3382	3.5	17564	3.6
Quebec	28254	29.1	145561	30.1
Ontario	29299	30.1	141698	29.3
Manitoba	3983	4.1	18824	3.9
Saskatchewan	2697	2.8	13491	2.8
Alberta	7352	7.6	43434	9.0
British Columbia	12646	13.0	58105	12.0
Yukon	122	0.1	440	0.1
Northwest Territories	181	0.2	559	0.1
Total Canada	**97193**	**100.0**	**483776**	**100.0**

Notes: The numbers in this table have been rounded.
[a] The capacity figures exclude purchases.

Source: Appendix Tables A5-1 and A5-2.

Tables 5-3 through 5-14 provide our projections of capacity and production by province and territory. More detailed information can be found in Appendix Tables A5-1 and A5-2.

Newfoundland and Labrador

In Newfoundland and Labrador, we project that the load will grow from a level of 10.7 terawatt hours in 1989 to 15.8 terawatt hours in 2010. This corresponds to an average annual growth rate of 1.9 percent.

The Newfoundland and Labrador system is physically divided, with over 75 percent of the load concentrated on the island and most of the major hydro resources located in Labrador. The Labrador load is 25 percent of the total provincial load and there is a 5225 megawatt hydro plant at Churchill Falls. Most of the plant output is sold to Quebec under a long-term contract. We assume that part of the output of Churchill Falls will continue to meet Labrador loads. On the island, most of the hydro sites which can be economically developed have been built. The island system has therefore become increasingly reliant on its oil generation; oil-fired capacity supplied about 21 percent of the in-province electrical energy demand in 1989.

As loads increase, new generating capacity, most likely gas turbines using light fuel oil will be required by 1993. Consistent with the province's published intentions and discussions with utility representatives, we assume in the long term

the island system will be supplied primarily from Labrador via an 800 MW high voltage direct current submarine cable link. Given the large investments that this project would entail and the considerable lead time required for approvals, design, and construction, we expect that the cable to Labrador would not be completed until 1998. This would be linked to the construction of the Gull Island hydro project and a recall of some of the Churchill Falls output in accordance with the sale contract with Quebec. In the interim, increased loads on the island would be met by additional gas turbine capacity, oil-fired units and by increasing generation from the existing oil-fired plants at Holyrood. In the event that the cable project were deferred or abandoned, Newfoundland would have to adopt an alternative scenario for supplying its island needs. Under these circumstances Newfoundland would likely serve its increasing loads by building additional base load plants burning coal or oil or, less likely, by building a nuclear plant.

In Newfoundland, non-utility producers generated about 466 gigawatt hours in 1989, about 4.4 percent of the provincial load; most of this was produced in hydro plants. We do not expect this percentage to increase rapidly over the study period. By 2010 we expect non-utility generation to account for about 520 gigawatt hours, 3.3 percent of in-province demand in the Control Case. The increase would come from an intensified use of wood wastes in the forest products industry.

Prince Edward Island

We project the demand for Prince Edward Island to grow from 727 gigawatt hours in 1989 to about 1126 gigawatt hours in

Table 5-3

Supply and Demand of Electricity in Newfoundland and Labrador

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	9 415	12 855	14 486
Other Domestic Demand	1261	1320	1320
Provincial Demand	**10676**	**14 175**	**15 806**
External Sales *	24 368	32 241	37 085
Total Demand (GW.h)	**35044**	**46416**	**52891**
Purchases **	0	0	0
Industry and Other Self-generation	1261	1320	1320
Utility Generation	**33 783**	**45 096**	**51 571**
of which: - Hydro	31 572	44 775	50 425
- Coal	0	0	0
- Nuclear	0	0	0
- Other	2211	321	1 146
Total Supply (GW.h)	**35044**	**46416**	**52891**
Capacity Summary (MW)			
Utility Generating Capacity	**6767**	**8 299**	**9 431**
Purchases **	0	0	0
Domestic Peak Demand	1734	2 466	2 901
System Peak Demand	6434	7 448	9 015
Remaining Capacity (Including Purchases)	333	851	416
Percent of System Peak	5.2	11.4	4.6

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			Approximate In-Service Dates
New Combustion Turbine	50 MW	(oil)	1993
New Combustion Turbine	50 MW	(oil)	1994
New Combustion Turbine	50 MW	(oil)	1994
Holyrood # 4	150 MW	(oil)	1995
New Combustion Turbine	50 MW	(oil)	1996
New Combustion Turbine	50 MW	(oil)	1997
Churchill Falls Recall	170 MW	(hydro)	1998
Gull Island	2264 MW	(hydro)	1999-2000

2010, an average annual growth rate of about 2.1 percent.

Although Prince Edward Island has sufficient oil-fired generating capacity to satisfy its own needs at present, for economic reasons it has been obtaining almost all of its electricity from New Brunswick via a submarine cable interconnection. Consultations with utility representatives lead us to believe that this interconnection will be upgraded so that the full 200 megawatt capacity of the submarine cable will be available for use.

Some of the existing on-island generating units are relatively old and are expected to be retired within the next fifteen years. We expect that they will be replaced by more gas turbine capacity and operated for peaking purposes as well as for back-up supply in cases of forced or maintenance outages of the submarine cable. We also expect that New Brunswick will continue to supply the base load energy and capacity needs to meet Prince Edward Island's demand through either firm system to system sales or unit participation agreements, and interruptible energy sales. Although legislation has been passed which encourages and provides on-island independent power production, we do not expect large non-utility supplies during the study period.

Nova Scotia

In 1989, the provincial demand for electricity in Nova Scotia was 9.0 terawatt hours. We anticipate that this will grow to 12.3 terawatt hours by 2010. This corresponds to an average annual load growth rate of 1.5 percent.

The province's generating capacity mix is currently about 35 percent oil, 47 percent coal and 18 percent hydro.

Table 5-4

Supply and Demand of Electricity in Prince Edward Island

	1989	2000	2010
	Energy Summary (GW.h)		
Utility Domestic Demand	728	924	1 126
Other Domestic Demand	0	0	0
Provincial Demand	**728**	**924**	**1 126**
External Sales *	0	0	0
Total Demand (GW.h)	**728**	**924**	**1126**
Purchases **	622	784	974
Industry and Other Self-generation	0	0	0
Utility Generation	**106**	**140**	**152**
of which: - Hydro	0	0	0
- Coal	0	0	0
- Nuclear	0	0	0
- Other	106	140	152
Total Supply (GW.h)	**728**	**924**	**1126**
	Capacity Summary (MW)		
Utility Generating Capacity	**112**	**122**	**156**
Purchases **	70	65	65
Domestic Peak Demand	134	168	206
System Peak Demand	134	168	206
Remaining Capacity (Including Purchases)	48	19	15
Percent of System Peak	35.8	11.3	7.3

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
New Combustion Turbine	10 MW	(oil)	1999
New Combustion Turbine	10 MW	(oil)	2000
New Combustion Turbine	10 MW	(oil)	2002
New Combustion Turbine	10 MW	(oil)	2004
New Combustion Turbine	10 MW	(oil)	2005
New Combustion Turbine	10 MW	(oil)	2006
New Combustion Turbine	10 MW	(oil)	2007
New Combustion Turbine	10 MW	(oil)	2008
New Combustion Turbine	10 MW	(oil)	2008

With the completion of the conversion of the Point Tupper No. 2 generating station in 1988 from oil to coal, Nova Scotia has completed its conversion of major oil-fired plants to coal. We are assuming that all new large base load capacity additions will burn Nova Scotia coal. This reflects the provincial policy of developing its indigenous coal resources. To meet both the provincial and federal emission standards on new thermal sources as well as the Federal/Provincial Acid Rain Agreement we have also assumed the new thermal plants will use either circulating fluidized-bed or conventional wet scrubber coal burning technologies to reduce sulphur dioxide emissions and acid rain depositions. Based on discussions with Nova Scotia Power, we expect that after the completion of the 150 megawatt coal-fired unit at Trenton this year the next major thermal unit to come into service will be the 165 megawatt Point Aconi circulating fluidized-bed coal combustion unit in 1993. Moreover, we project that additional coal-fired units will be added at Point Aconi for base load, and gas turbine units will be built for peaking purposes during the study period.

There is a 20 megawatt tidal power plant in operation at Annapolis Royal but, because of the relatively high cost of tidal units, we expect no further development of tidal power within the study period.

Nova Scotia's non-utility electricity producers generated 296 gigawatt hours in 1989, about 3.3 percent of the provincial total. Most of this electricity was produced by the forest products industry. We anticipate that non-utility generation will increase by about 79 megawatts by 2000 as a result of the government's policy to encourage the development of power production within the province. By 2010, non-utility production is estimated at about 750 gigawatt hours, or 4 percent of total production.

Nova Scotia and New Brunswick have traded electricity on an interruptible basis for some time. On average, Nova Scotia buys and sells the same amount of electricity from and to New Brunswick. Most of the trade is in economy energy. We assume that these transactions will continue at a level consistent with recent past practice.

Table 5-5

Supply and Demand of Electricity in Nova Scotia

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	8 754	10 375	11 857
Other Domestic Demand	296	400	400
Provincial Demand	**9050**	**10 775**	**12 257**
External Sales *	341	400	400
Total Demand (GW.h)	**9391**	**11175**	**12657**
Purchases **	441	750	750
Industry and Other Self-generation	296	400	400
Utility Generation	**8 654**	**10 025**	**11 507**
of which: - Hydro	934	1 064	1 064
- Coal	5 345	8 359	9 605
- Nuclear	0	0	0
- Other	2375	602	838
Total Supply (GW.h)	**9391**	**11175**	**12657**
Capacity Summary (MW)			
Utility Generating Capacity	**2093**	**2 408**	**2 623**
Purchases **	0	50	50
Domestic Peak Demand	1638	1 896	2 135
System Peak Demand	1638	1 896	2 135
Remaining Capacity (Including Purchases)	455	562	538
Percent of System Peak	27.8	29.6	25.2

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
Trenton #6	150 MW	(coal)	1991
Point Aconi #1 CFB	165 MW	(coal)	1993
New Combustion Turbine	50 MW	(oil)	2007
Point Aconi #2	165 MW	(coal)	2008

New Brunswick

We project that by 2010 in-province demand in New Brunswick will grow to about 18.7 terawatt hours from the 1989 level of 13.6 terawatt hours. This translates into an average annual load growth rate of about 1.5 percent.

New Brunswick has a 1000 MW oil-fired plant at Coleson Cove which we expect will be operated to balance the utility's energy requirements after base load nuclear and coal-fired generation have been utilized. We expect coal from various sources will be used to fire New Brunswick's thermal plants, including both domestic and foreign bituminous coals as well as an emulsion of water and bitumen imported from Venezuela called "Orimulsion" which will be used at the Dalhousie coal-fired plant. With the completion of the 440 MW coal-fired unit at Belledune in 1994, we expect that further generating capacity will include gas turbines for peaking purposes and additional 440 MW coal-fired units at Belledune to satisfy the utility's base load requirements. Also included in New Brunswick's generation program are a total of 500 MW of gas turbine capacity at Millbank and St. Rose, expected to come into service by 1992, of which 400 MW will be purchased by Quebec under a long-term contract.

To meet the Federal-Provincial Acid Rain Agreements as well as relevant federal and provincial criteria on air quality, New Brunswick intends to install scrubbers on all new fossil fuel-fired plants, and to use lower sulfur coal at some of its existing plants.

The province currently has a mix of about 46 percent oil, 27 percent hydro, 19 percent nuclear[1] and 8 percent coal capacity.

Non-utility producers generated 812 gigawatt hours in 1989, about 6 percent of the provincial demand. Most of this was produced at hydro plants owned by forest products companies. We expect that private electricity generation will increase modestly in the study period, reflecting primarily the more intense use of wood waste. By 2010, we project non-utility production to total 835 gigawatt hours or almost 5 percent of total production.

A major source of electricity for New Brunswick has been Quebec, with which it shares a total of about

1 This is the 635 megawatt Point Lepreau nuclear unit and includes a portion exported to New England until 1994.

Table 5-6

Supply and Demand of Electricity in New Brunswick

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	12 614	15 695	17 757
Other Domestic Demand	952	975	975
Provincial Demand	**13566**	**16 670**	**18 732**
External Sales *	6 559	3 406	2 828
Total Demand (GW.h)	**20125**	**20076**	**21560**
Purchases **	2561	450	450
Industry and Other Self-generation	952	975	975
Utility Generation	**16 612**	**18 651**	**20 135**
of which: - Hydro	2 194	2 576	2 576
- Coal	1 864	5 893	5 893
- Nuclear	5269	4 728	4 728
- Other	7285	5 454	6 938
Total Supply (GW.h)	**20125**	**20076**	**21560**
Capacity Summary (MW)			
Utility Generating Capacity	**3193**	**4 133**	**4 723**
Purchases **	350	0	0
Domestic Peak Demand	2250	2 715	3 071
System Peak Demand	2637	3 292	3 548
Remaining Capacity (Including Purchases)	906	841	1175
Percent of System Peak	34.4	25.5	33.1

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
Mill Bank # 1-4	400 MW	(oil)	1991
Sainte Rose	100 MW	(oil)	1992
Belledune # 1	440 MW	(coal)	1994
New Combustion Turbine	150 MW	(oil)	2007
Belledune # 2	440 MW	(coal)	2010

1000 megawatts of interconnection capacity. New Brunswick uses this mainly to make interruptible energy purchases. Most of the purchased energy is used to displace generation from fossil fuels in New Brunswick; but, in cooperation with Quebec, some of this purchased energy, along with some of New Brunswick's own surplus energy generated from fossil fuel and hydro, is sold on an interruptible basis to Nova Scotia, Prince Edward Island and New England. Interruptible purchases from Quebec are expected to be modest in the near term. This is because of the expected lower levels of hydro surpluses on the Quebec system as well as Quebec's expanded access to more attractive markets in the U.S., where the cost of alternative sources is higher than in New Brunswick. However, when the major hydraulic development of Grande Baleine comes into service in the early 2000s New Brunswick may once again become a major purchaser of interruptible energy.

We expect that New Brunswick will continue making interruptible energy sales to Nova Scotia and Prince Edward Island. We also expect that New Brunswick will sell small blocks of firm capacity and energy from specific plants to Prince Edward Island, as loads grow in that province.

New Brunswick's only nuclear plant (Point Lepreau 1) is a 635 megawatt unit. About 230 megawatts of its capacity is dedicated to firm exports until 1994. Although New Brunswick could opt to build a second nuclear unit at Point Lepreau, it has been reluctant to do so because of the large up-front financial risks. For this reason we have not included it in our study. We have however, assumed that the Lepreau #1 nuclear unit participation contracts with New England utilities will be renegotiated when they terminate in 1994.

Quebec

In 1989, the in-province load was 163.5 terawatt hours, of which about 16 percent was purchased energy generated at Churchill Falls in Labrador. The load is projected to grow to 226.4 terawatt hours in 2010 in the Control Case. The corresponding average annual load growth rate is 1.6 percent. Quebec's own generating capacity mix is currently about 94 percent hydro, 4 percent oil and 2 percent nuclear.

Hydro-Québec, in its recently published development plan[1], noted that it had adopted the principle of sustainable development and that its first contribution to the realization of sustainable development was to promote energy conservation to reduce electricity demand growth. The utility aims for substantial energy savings and peak demand reductions which will be supported by rate structures that reflect the cost of supply in order to encourage the rational use of electricity. Our demand projections incorporate these strategies and we anticipate significant reductions in the annual peak load below what would be the case if such resources were not adopted.

In Quebec, non-utility producers generated 17.5 terawatt hours in 1989, about 10.7 percent of the provincial demand. Most of this was hydro production by the aluminium industry. There is also a small potential for private power production - small-hydro, cogeneration, and municipal refuse incineration. We do not expect much expansion of non-utility production in Quebec. By 2010, we project that non-utility production will be about 21.5 terawatt hours, almost 10 percent of total production.

Quebec has a large reservoir storage capacity and is able to regulate its hydroelectric production to compensate for fluctuations in seasonal and annual rainfall. This enables Quebec to supply its own loads while providing it with substantial operational flexibility to make out-of-province sales at times when market prices are most attractive, thereby maximizing the value of this energy for Quebec.

Consistent with the utility's supply program[1] we project that within this decade Hydro-Québec will complete all its hydraulic generation in the La Grande complex in order to meet its growing in-province loads and outside firm commitments up to the year 2000. After 2000, we project that the first of several hydroelectric generating stations of the Grande-Baleine complex will come into service, to be followed by development of the Nottaway Broadback Rupert watershed. The generation expansion program we assumed in this study also includes supplies to support up to 3500 MW of long-term firm capacity and associated energy exports, including the 800 MW seasonal summer sales to New York Power Authority (see section 5.2). We also expect that Hydro-Québec will build additional transmission lines and proceed with a major upgrading of the transmission system to bring the reliability of the Quebec network in line with the criteria of the North American Electric Reliability Council.

The supply strategy of Hydro-Québec may well be affected by forthcoming environmental reviews.

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1 Proposed Hydro-Québec Development Plan 1990-1992, Horizon 1999, March 1990.

In Canada, Quebec has major interconnections with Newfoundland and Labrador, New Brunswick and Ontario. We expect that purchases from the Churchill Falls generating station in Labrador will continue as contracted. Sales to New Brunswick have almost always been at a level close to the physical limit of the interconnections. We expect that this will continue until the early 1990s. Thereafter, the sales will vary depending on the amount of surplus energy available in Quebec. As mentioned above, we are also including a firm twenty year purchase of up to 400 MW of peaking capacity from New Brunswick which will commence in 1992.

Current sales of interruptible energy to Ontario have been modest and we anticipate that they will continue to be modest in the future as Quebec's surpluses diminish and Ontario's Darlington nuclear units come into service. For Quebec, Ontario is a less lucrative market than the U.S. for economy energy sales because of Ontario's economic nuclear and efficient coal-burning plants.

Ontario

We project that by 2010, the in-province demand for electricity will grow to 202.8 terawatt hours, from the 1989 level of 147.5 terawatt hours. This corresponds to an annual average growth rate of 1.5 percent.

In 1989, non-utility producers generated 4.4 terawatt hours of electricity or 3 percent of the provincial demand. While most of this was produced in relatively small hydro facilities, a large and growing proportion was generated from fossil and by-product fuels. As part of its supply options review,[1] Ontario has consid-

1 "Providing the Balance of Power" Ontario Hydro's Plan to serve customers' Electricity Needs - 1990.

Table 5-7

Supply and Demand of Electricity in Quebec

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	141 888	170 471	203 292
Other Domestic Demand	21636	23100	23100
Provincial Demand	**163524**	**193 571**	**226 392**
External Sales *	8 436	23850	26900
Total Demand (GW.h)	**171960**	**217421**	**253292**
Purchases **	26399	34840	39584
Industry and Other Self-generation	21636	23100	23100
Utility Generation	**123 925**	**159 481**	**190 608**
of which: - Hydro	117 381	153 890	183 756
- Coal	0	0	0
- Nuclear	4820	5 101	5 101
- Other	1724	490	1 751
Total Supply (GW.h)	**171960**	**217421**	**253292**
Capacity Summary (MW)			
Utility Generating Capacity	**24985**	**30 970**	**38 250**
Purchases **	5100	6162	7294
Domestic Peak Demand	26337	31 060	36 764
System Peak Demand	27132	32 566	39 520
Remaining Capacity (Including Purchases)	2953	4566	6024
Percent of System Peak	10.9	14.0	15.2

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
Iles De La Madeleine	57 MW	(diesel)	1990
Hart Jaunes	48 MW	(hydro)	1991
LG-2A	1902 MW	(hydro)	1991-1992
Roues Manic 5	230 MW	(hydro)	1993
Brisay	380 MW	(hydro)	1993
LA-1	820 MW	(hydro)	1994
LG-1	1308 MW	(hydro)	1994-1995
LA-2	270 MW	(hydro)	1998
Eastmain-1	470 MW	(hydro)	1999
New Combustion Turbines	300 MW	(oil)	2000
Grande Baleine 1,2,3	3060 MW	(hydro)	2001-2003
Manic-3 P.A.	270 MW	(hydro)	2004
Manic-2 P.A.	374 MW	(hydro)	2005
Manic-1 P.A.	191 MW	(hydro)	2006
Sainte Marguerite	800 MW	(hydro)	2006
NBR 1,2,3,4	8400 MW	(hydro)	2007- - - -

ered the possible contributions of additional non-utility electricity producers: these include industrial cogenerators, private and municipal power companies and individuals which are projected to contribute about 1400 additional megawatts of capacity by 2010. By the year 2010, we project that non-utility producers will generate about 14.8 terawatt hours, some 7 percent of the total production.

Ontario's mix of generating capacity is currently about 34 percent nuclear, 30 percent coal, 24 percent hydroelectric and 12 percent natural gas, oil and other sources.

We anticipate that the four unit Darlington nuclear generating station (3524 megawatts in total) will be completed on schedule by 1992. Following Darlington, and within the range of the development options currently being considered, we also assume that Ontario will opt for a mixed electricity supply strategy which includes the following elements:

- A demand management program encompassing:
  - Electrical efficiency improvements via the promotion of efficiency improving technologies such as improved insulation levels in new and existing homes, heat pumps, improved climate control in commercial buildings, and high efficiency lighting.
  - Load shifting by encouraging customers to shift their demand from peak to non-peak periods through time-of-use rates, for example by providing industrial customers with economic incentives, and through direct control of customer demand, with their permission, for example by

Table 5-8

Supply and Demand of Electricity in Ontario

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	141 670	164 044	195 345
Other Domestic Demand	5822	7477	7477
Provincial Demand	**147492**	**171 521**	**202 822**
External Sales *	4 405	7 612	7 202
Total Demand (GW.h)	**151897**	**179133**	**210024**
Purchases **	10383	11386	17113
Industry and Other Self-generation	5822	7477	7477
Utility Generation	**135 692**	**160 270**	**185 434**
of which: - Hydro	35 135	35 321	39 030
- Coal	33 775	29 987	42 383
- Nuclear	65261	94 949	103 453
- Other	1521	13	568
Total Supply (GW.h)	**151897**	**179133**	**210024**
Capacity Summary (MW)			
Utility Generating Capacity	**28091**	**31 490**	**36 304**
Purchases **	84	1388	2449
Domestic Peak Demand	24135	26 871	31 976
System Peak Demand	24182	26 873	31 978
Remaining Capacity (Including Purchases)	3993	6005	6775
Percent of System Peak	16.5	22.3	21.2

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			Approximate In-Service Dates
Darlington A #1-2	1762 MW	(nuclear)	1990
Darlington A #3	881 MW	(nuclear)	1991
Darlington A #4	881 MW	(nuclear)	1992
Little Jackfish	130 MW	(hydro)	2004
Gibson+Big Chute	15 MW	(hydro)	2004
Mattagami Complex	379 MW	(hydro)	2004-2005
New Combustion Turbines	336 MW	(gas)	2004
Niagara Redevelopment	550 MW	(hydro)	2005
New Combustion Turbines	336 MW	(gas)	2006
Abitibi Complex	932 MW	(hydro)	2006-2007
New Nuclear #1	881 MW	(nuclear)	2008
New Nuclear #2	881 MW	(nuclear)	2009
New Nuclear #3	881 MW	(nuclear)	2010

means of devices that shut off water heaters for selected periods of time.

- Interruptible contracts which allow the utility to interrupt electricity as circumstances require, thereby offering those customers lower electricity bills for those willing to accept a lower level of electric reliability.

Based on discussions with Ontario Hydro, this demand management is projected to save about 3500 megawatts of peak demand by the year 2000.

- Ontario will build and redevelop several small and medium sized hydro facilities as well as construct gas turbine and new nuclear capacity, as needed, early in the next century. We expect that the Pickering and Bruce nuclear power plants will be retubed during the study period. We also expect Ontario will install flue gas desulphurisation equipment (scrubbers) on several of its major coal-burning units, enabling them to be more intensively used while respecting the more stringent acid gas emission limitations recently imposed by the province. In addition we anticipate that Ontario will also meet the emission limits established pursuant to the "Canada-Ontario Agreement Respecting a Sulphur Dioxide Reduction Program" as well as the federal objectives of maintaining the year 2000 CO_2 emissions at 1990 levels.

- Ontario will continue to encourage non-utility generation of electricity from independent power producers (IPPs) as well as from private and municipal utilities. We estimate that currently some 200 megawatts of production by IPPs are in service and interconnected with the province-wide transmission and distribution network. By 2010 we project that about 1400 megawatts will be in place to be sold to the utility.

Clearly, the supply strategy eventually adopted by Ontario Hydro is uncertain pending competion of the public review currently being undertaken by the Ontario Environmental Assesment Board.

Manitoba

In 1989, the in-province demand for electricity in Manitoba was 17.6 terawatt hours. By 2010, the demand is expected to grow to 21.7 terawatt hours, corresponding to an average annual load growth rate of about 1.0 percent.

Table 5-9

Supply and Demand of Electricity in Manitoba

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	17 569	19 396	21 614
Other Domestic Demand	69	85	85
Provincial Demand	**17638**	**19 481**	**21 699**
External Sales *	3 758	11194	13417
Total Demand (GW.h)	**21396**	**30675**	**35116**
Purchases **	2572	1111	101
Industry and Other Self-generation	69	85	85
Utility Generation	**18 755**	**29 479**	**34 930**
of which: - Hydro	18 300	29 463	34 930
- Coal	435	16	0
- Nuclear	0	0	0
- Other	20	0	0
Total Supply (GW.h)	**21396**	**30675**	**35116**
Capacity Summary (MW)			
Utility Generating Capacity	**3953**	**5 804**	**6 235**
Purchases **	300	500	500
Domestic Peak Demand	3399	3 690	4 045
System Peak Demand	3511	4 590	5 545
Remaining Capacity (Including Purchases)	742	1714	1190
Percent of System Peak	21.1	37.3	21.5

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
Limestone	1280 MW	(hydro)	1990-1992
Conawapa	1230 MW	(hydro)	1999-2001
Wuskwatim	352 MW	(hydro)	2010-2011

In 1989, non-utility producers generated about 69 gigawatt hours, most of it from hydro plants. Because of the low cost of Manitoba's utility-produced electricity, we do not expect non-utility producers to increase in importance in Manitoba during the study period.

Manitoba's current generating capacity mix is about 88 percent hydro and 9 percent coal, with the balance being primarily light oil, diesel and natural gas. In accordance with the utility's plan we expect that Manitoba will continue to use its abundant undeveloped hydro resources to meet its projected loads and firm commitments. To meet its 1000 megawatt long-term firm sale to Ontario, Manitoba will commission the Conawapa hydroelectric generating station on the Nelson River and a 1500 megawatt intertie with Ontario Hydro in 2000.

Saskatchewan

By 2010, we project that in-province demand for electricity in Saskatchewan will grow to 15.5 terawatt hours, from the 1989 level of 13.6 terawatt hours. This corresponds to an average annual growth rate of 0.6 percent.

In Saskatchewan, non-utility producers generated about 395 gigawatt hours in 1989, just under 3 percent of the provincial total. Except for the 40 MW purchase from the Athabasca hydro plant (owned by independent power producers) which we expect to come on line in 1995, we have assumed no additional major non-utility production over the study period. We project that, by 2010, non-utility producers will supply 490 gigawatt hours, over 3 percent of total production.

Saskatchewan is largely self-reliant in capacity and energy. It conducts only modest transactions with Manitoba, Alberta and the United States. In 1987, Saskatchewan and Alberta completed a new high-voltage direct-current interconnection. The usable capacity of this interconnection is approximately 110 megawatts. It will confer a benefit to Saskatchewan of about 100 megawatts of reserve equivalent and give both utilities the ability to make economy and other transactions.

The province's current mix of generating facilities is about 58 percent coal, 31 percent hydroelectric and 11 percent natural gas, diesel, and light oil. Since Saskatchewan has a substantial coal resource, we assume that new coal-fired units will be built as needed, similar to the Shand 1 generating unit scheduled for completion in 1992. We also assume that peaking needs will be met by a combination of out-of-province purchases and gas-burning combustion turbine units.

Table 5-10

Supply and Demand of Electricity in Saskatchewan

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	13 230	14 060	15 054
Other Domestic Demand	395	405	405
Provincial Demand	**13625**	**14 465**	**15 459**
External Sales *	1 202	1 208	208
Total Demand (GW.h)	**14827**	**15673**	**15667**
Purchases **	1336	1365	1365
Industry and Other Self-generation	395	405	405
Utility Generation	**13 096**	**13 903**	**13 897**
of which: - Hydro	2 832	3 795	3 795
- Coal	9 804	10 052	10 080
- Nuclear	0	0	0
- Other	460	56	22
Total Supply (GW.h)	**14827**	**15673**	**15667**
Capacity Summary (MW)			
Utility Generating Capacity	**2617**	**2 897**	**3 177**
Purchases **	225	265	265
Domestic Peak Demand	2423	2 494	2 669
System Peak Demand	2423	2 494	2 669
Remaining Capacity (Including Purchases)	419	668	773
Percent of System Peak	17.3	26.8	29.0

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
Shand # 1	280 MW	(coal)	1992
Shand # 2	280 MW	(coal)	2007

Alberta

The 1989 in-province demand for electricity in Alberta was 41.2 terawatt hours. We project that this will grow to 55.6 terawatt hours by 2010. The corresponding average annual load growth rate is 1.4 percent.

Alberta's current generating capacity mix is about 67 percent coal, 21 percent gas, 11 percent hydro and 1 percent oil and other.

In 1989, non-utility producers generated 3.5 terawatt hours, about 8 percent of the provincial total. This production was based largely on the use of by-product fuels and natural gas. Based on projections made by the Alberta Energy Resources Conservation Board we assume that by 2010, industrial generation and private producers will have increased their capabilities by about 55.7 megawatts. By then non-utility producers are projected to generate about 7.3 terawatt hours, or some 13 percent of total production.

We have assumed Alberta will adopt some demand management initiatives to reduce the requirements for additional capacity. However, given Alberta's high overall load factor, we see little opportunity for shifting peak demand to achieve peak load reductions.

Based on our load projections and with the completion of two 17 megawatt and one 30 megawatt gas-fired combined-cycle units at Medicine Hat in 1993 and 1996 respectively and the 400 megawatt Genessee # 1 coal-fired unit in 1995, Alberta will not require further base load capacity additions until the early 2000s. As Alberta's coal resources are plentiful and inexpensive to extract we estimate

Table 5-11

Supply and Demand of Electricity in Alberta

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	37 708	42 974	48 347
Other Domestic Demand	3468	6226	7297
Provincial Demand	**41176**	**49 200**	**55 644**
External Sales *	2 519	2 490	2 290
Total Demand (GW.h)	**43695**	**51690**	**57934**
Purchases **	261	325	325
Industry and Other Self-generation	3468	6226	7297
Utility Generation	**39 966**	**45 139**	**50 312**
of which: - Hydro	1 598	1 636	1 636
- Coal	34 087	41 381	45 837
- Nuclear	0	0	0
- Other	4281	2 122	2 839
Total Supply (GW.h)	**43695**	**51690**	**57934**
Capacity Summary (MW)			
Utility Generating Capacity	**6929**	**7 603**	**8 580**
Purchases **	425	525	525
Domestic Peak Demand	5686	6 379	7 177
System Peak Demand	5686	6 379	7 177
Remaining Capacity (Including Purchases)	1668	1749	1928
Percent of System Peak	29.3	27.4	26.9

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			Approximate In-Service Dates
Sheerness # 2	383 MW	(coal)	1990
Medicine Hat Combined-Cycle	34 MW	(gas)	1993
Genesee # 1	406 MW	(coal)	1995
Medicine Hat Combined-Cycle	30 MW	(gas)	1996
New Combustion Turbine	100 MW	(gas)	1999
New Combustion Turbines	200 MW	(gas)	2000
New Combustion Turbine	100 MW	(gas)	2001
New Coal # 1	375 MW	(coal)	2002
New Coal # 2	375 MW	(coal)	2003
New Combustion Turbine	100 MW	(gas)	2004
New Combustion Turbine	100 MW	(gas)	2005
New Combustion Turbine	100 MW	(gas)	2006
New Coal # 3	375 MW	(coal)	2008

that all new large capacity additions will be coal-fired plants of the type and size of the Genessee units. We also anticipate that new peaking capacity needs will be served using natural gas-fired combustion turbine units.

Alberta's high voltage interconnection with British Columbia with a rated transfer capacity of about 800 MW allows Alberta's thermal and British Columbia's hydraulic system to be operated in a coordinated and complementary manner for mutual economic and reliability benefits. As noted in section 5.2.1, the Alberta power system is an ideal complement to the seasonal and annual variability of British Columbia's hydroelectric system.

British Columbia

In British Columbia, the 1989 in-province electricity demand was 55.9 terawatt hours. We project that this will grow to 74.3 terawatt hours in 2010. This translates into an average annual growth rate of 1.4 percent.

British Columbia's generating capacity mix is currently about 87 percent hydro, 9 percent natural gas and 4 percent oil and other fuel types.

In 1989, non-utility producers generated 12.2 terawatt hours of electricity, about 22 percent of total in-province demand. Most of this production was generated at hydro plants for use by the aluminium industry. Based on actual contracts agreed between B.C. Hydro and the private sector, non-utility production is projected at about 17.2 terawatt hours, some 23 percent of total production in 2010.

Although British Columbia has a large undeveloped hydroelectric potential, the utility's published electricity development plan[1] illustrates a number of available options that the province could utilize to meet future electricity needs. The options which we have incorporated in our expansion plans for British Columbia include:

- the Power Smart program which is intended to reduce the growth in future demand by encouraging customers to use electricity more efficiently;
- the Resource Smart program which is intended to ensure that full economic use is made of the capacity and energy

1 BC Hydro 1990 Electricity Plan A perspective of Supply and Demand Options - May 1990.

Table 5-12

Supply and Demand of Electricity in British Columbia

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	42 919	49 850	60 108
Other Domestic Demand	12993	14200	14200
Provincial Demand	**55912**	**64 050**	**74 308**
External Sales *	6 343	6 300	6 300
Total Demand (GW.h)	**62255**	**70350**	**80608**
Purchases **	4501	9066	10566
Industry and Other Self-generation	12993	14200	14200
Utility Generation	**44 761**	**47 084**	**55 842**
of which: - Hydro	39 973	46 491	53 298
- Coal	0	0	0
- Nuclear	0	0	0
- Other	4788	593	2 544
Total Supply (GW.h)	**62255**	**70350**	**80608**
Capacity Summary (MW)			
Utility Generating Capacity	**10610**	**10 610**	**12 025**
Purchases **	0	1116	1616
Domestic Peak Demand	7350	8 173	9 814
System Peak Demand	7460	9 023	10 664
Remaining Capacity (Including Purchases)	3150	2703	2977
Percent of System Peak	42.2	30.0	27.9

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
Keenleyside	240 MW	(hydro)	2003
Peace Site C	900 MW	(hydro)	2004-2005
Murphy Creek	275MW	(hydro)	2009-2010

potential of existing generation facilities;

- coordination and purchase agreements with other utilities or larger industries with electric generation capability to operate their respective systems in coordination with BC Hydro's to produce benefits for both;

- the Canadian entitlement to the downstream power and energy benefits associated with the Columbia River Treaty which will gradually revert to British Columbia beginning in 1998. We have assumed that BC will repatriate its entitlement, which could add about 480 gigawatt hours in 1998, increasing to about 4700 gigawatt hours by 2005 to British Columbia's electricity supplies;

- encouraging the development of new electricity supplies by private producers to supply a portion of the province's domestic requirements and for export. We have included in our projections the following announced IPP plans:

  - N.W. Energy's Williams Lake 55 megawatt wood waste power plant expected in service in 1993;

  - Westcoast Energy's McMahon natural gas-fired 105 megawatt unit expected in service in 1994;

  - Northern Utility's Mamquam 50 megawatt hydro unit expected in service in 1994;

  - the 300 megawatt expansion of the Kemano hydro plant owned by aluminium producer Alcan which is scheduled to be completed in 1995.

We project that British Columbia will require additional capacity by the early 2000s to meet the anticipated growth in demand. Development of British Columbia's hydro sites would resume at that time with the construction of the 240 megawatt Keenleyside and the 900 megawatt Peace Site C hydro power plant.

Yukon

The Yukon's electrical energy demand in 1989 was 440 gigawatt hours. We expect this to grow to 566 gigawatt hours in 2010. This corresponds to an average annual growth rate of 1.2 percent.

Table 5-13

Supply and Demand of Electricity in Yukon

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	440	487	566
Other Domestic Demand	0	0	0
Provincial Demand	**440**	**487**	**566**
External Sales *	0	0	0
Total Demand (GW.h)	**440**	**487**	**566**
Purchases **	0	0	0
Industry and Other Self-generation	0	0	0
Utility Generation	**440**	**487**	**566**
of which: - Hydro	405	393	400
- Coal	0	0	0
- Nuclear	0	0	0
- Other	35	94	166
Total Supply (GW.h)	**440**	**487**	**566**
Capacity Summary (MW)			
Utility Generating Capacity	**122**	**129**	**150**
Purchases **	0	0	0
Domestic Peak Demand	79	96	111
System Peak Demand	79	96	111
Remaining Capacity (Including Purchases)	43	33	39
Percent of System Peak	54.4	34.4	35.1

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			**Approximate In-Service Dates**
New Internal Combustion	7 MW	(diesel)	1999
New Internal Combustion	7 MW	(diesel)	2003
New Internal Combustion	7 MW	(diesel)	2006
New Internal Combustion	7 MW	(diesel)	2010

In 1989, 92 percent of electrical energy generation was from hydro, and this was concentrated at Whitehorse. Although there may be a role for other small hydro or wind projects, we assume that future capacity additions in isolated locations will be diesel. A substantial amount of extra reserve diesel capacity is maintained to provide adequate security of supply to isolated communities during the long winter season.

Northwest Territories

In 1989, the Northwest Territories' electricity demand was 559 gigawatt hours. We anticipates that this will grow to about 775 gigawatt hours in 2010, corresponding to an average annual growth rate of 1.6 percent.

Non-utility producers generated about 106 gigawatt hours or about 21 percent of the territorial consumption in 1989. As a result of mine closures non-utility generation decreases to 26 megawatt hours in 1990. We assume that no new non-utility plants will be built in the study period.

While the Northwest Territories' generating capacity is made up of about 76 percent diesel units and combustion turbines, and 24 percent hydro plants; electricity generation in 1989 was about 46 percent hydro. The reason for this seeming imbalance is that, as in the Yukon, much of the hydro generation is concentrated near the capital, Yellowknife, the rest of the territory being dependent mainly on oil. We assume that all new capacity additions will be diesel although, as in the Yukon, there may be a role for small hydro and wind projects.

5.4 Interruptible and Total Trade

Interruptible Exports

Over and above firm electricity trade, interconnected Canadian and U.S. utilities also engage in exchanges and sales of electrical energy, generally of an interruptible nature, pursuant to their bilateral interconnection agreements. The purposes of such trade are to optimize and coordinate their system operations for mutual economic, environmental and reliability benefits.

Excess interruptible energy capability is an inherent characteristic of electric power systems, be they hydro, thermal, or a mixture of both

Table 5-14

Supply and Demand of Electricity in Northwest Territories

	1989	2000	2010
Energy Summary (GW.h)			
Utility Domestic Demand	443	635	749
Other Domestic Demand	116	26	26
Provincial Demand	**559**	**661**	**775**
External Sales *	0	0	0
Total Demand (GW.h)	**559**	**661**	**775**
Purchases **	0	0	0
Industry and Other Self-generation	116	26	26
Utility Generation	**443**	**635**	**749**
of which: - Hydro	233	280	280
- Coal	0	0	0
- Nuclear	0	0	0
- Other	210	355	469
Total Supply (GW.h)	**559**	**661**	**775**
Capacity Summary (MW)			
Utility Generating Capacity	**156**	**156**	**177**
Purchases **	0	0	0
Domestic Peak Demand	80	115	136
System Peak Demand	80	115	136
Remaining Capacity (Including Purchases)	76	41	41
Percent of System Peak	95.0	35.7	30.1

Notes: Numbers in this table have been rounded.
(*)'External Sales' include interprovincial sales and exports.
(**)Include purchases from independent power producers and purchases from out of province.

Timing of Major Projects

Project Description			Approximate In-Service Dates
New Internal Combustion	7 MW	(diesel)	2003
New Internal Combustion	7 MW	(diesel)	2006
New Internal Combustion	7 MW	(diesel)	2008

modes of generation. In a hydro system, capacity additions are based on dependable flow conditions while actual production will vary with actual river flows which on average are greater, resulting periodically in energy excess to system needs. In a thermal system the average availability of fossil fuel-fired plants is usually greater than the load factor of the system. As a result, these plants are available to produce excess electricity for sale if there are economic benefits for seller and buyer.

A review of Canada - U.S. trade in interruptible energy shows that Canadian utilities whose generation is predominantly hydro, coal, and nuclear have production costs significantly below those of neighbouring U.S. utilities which are more dependent on oil- and coal-fired generation. Energy flows have therefore tended to be, on balance, from Canada to the U.S. However, an exception to this general trend has occurred in the last few years for a number of reasons (outlined in section 5.2).

We project that levels of interruptible exports will start to increase from recent low levels as new generating facilities are brought into service and as precipitation levels return to their longer-term averages. Interruptible exports, which in 1990 were about 7.8 terawatt hours (47 percent of total exports), are projected to increase to about 15.0 terawatt hours in 2010, about 32 percent of total gross exports of some of 47 terawatt hours projected for that year.

Total International Trade

Total gross exports, including firm and interruptible sales, reached maximum historic levels in 1987 of 44 terawatt hours and declined to 18 terawatt hours by 1989. With the increases in firm and interruptible exports discussed above, we project total gross exports from Canada increasing to about 45 terawatt hours in the year 2000 and to some 47 terawatt hours in 2010 (Figures 5-4, 5-5 and Table 5-15).

Table 5-15

Gross Electricity Exports by Province

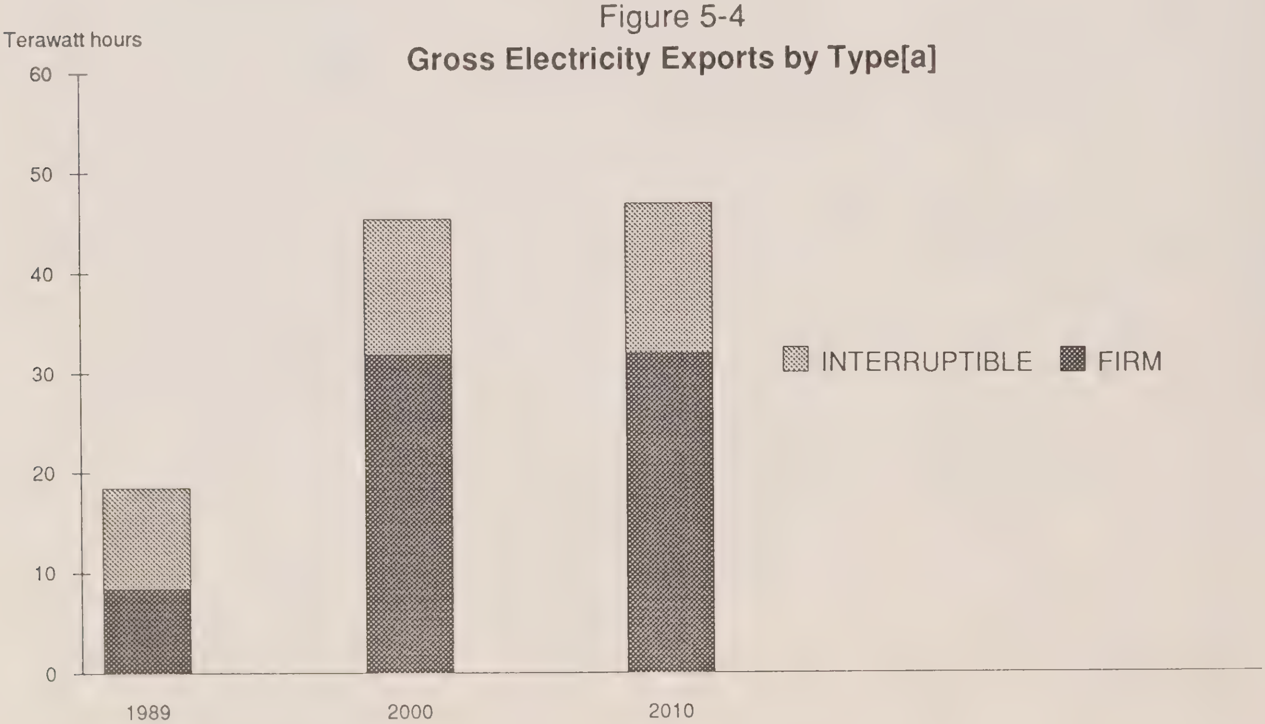
(Terawatt hours)[a]

	1989	2000	2010
New Brunswick	4.5	2.6	1.9
Quebec	5.7	22.9	26.0
Ontario	2.7	7.5	7.2
Manitoba	1.2	5.9	5.3
Saskatchewan	0.0 *	0.0 *	0.0 *
British Columbia	4.4	6.4	6.4
Canada Total	**18.5**	**45.3**	**46.8**

Note: Numbers in this table have been rounded.
[a] Excludes exchanges
*Less than 0.1

Figure 5-4

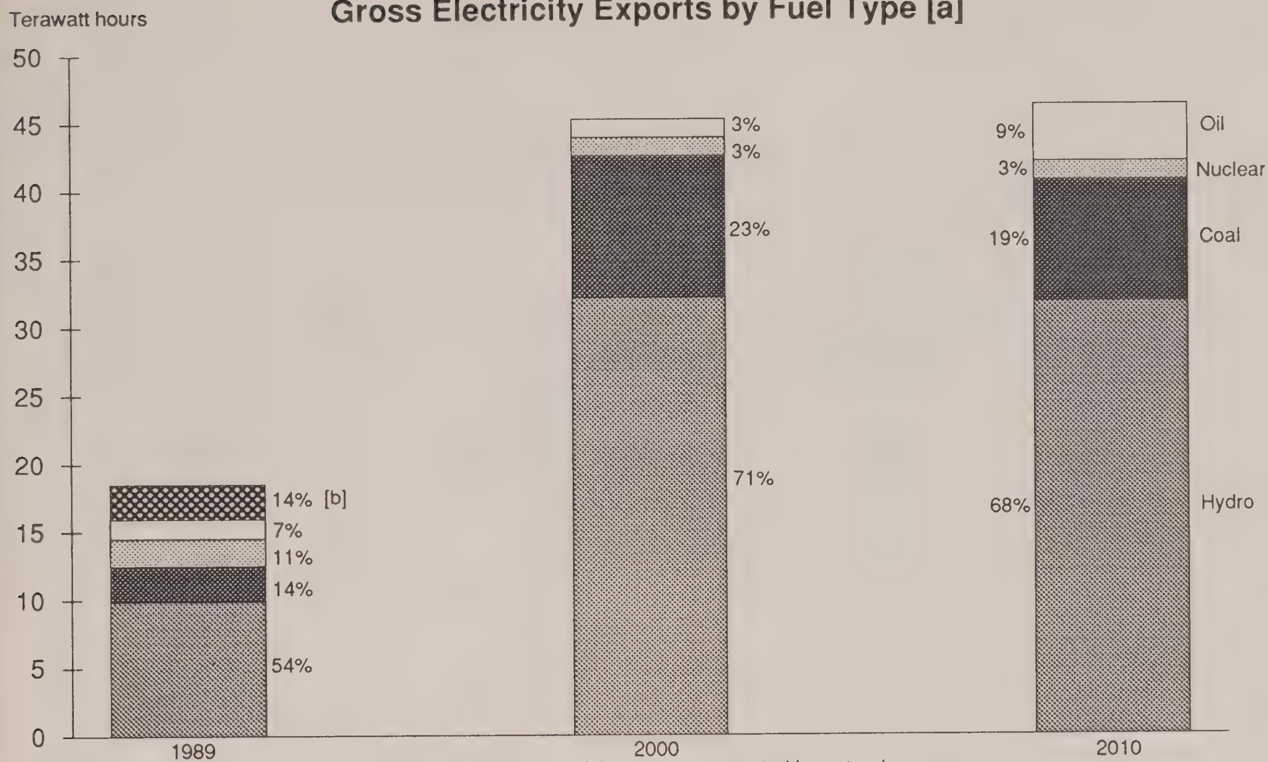
Gross Electricity Exports by Type[a]



[a] Excludes exchanges

Figure 5-5

Gross Electricity Exports by Fuel Type [a]



[a] Excludes exchanges. [b] Natural gas. No forecast of electricity exports generated by natural gas.
Source: Appendix Table A5-6

Interruptible Interprovincial Trade

In addition to firm interprovincial trade discussed in section 5.2.2, interconnected Canadian utilities also engage in exchanges and sales of electricity generally of an interruptible nature, pursuant to their bilateral interconnection agreements, for the same reasons mentioned before. Consistent with the aim of maximizing the economic gains from interconnected operation, we base our trade projection on the presumption that in general surpluses will be sold into the most lucrative market, which is typically the export market because of the higher U.S. cost of generation. Interruptible sales to the export market are therefore generally expected to take precedence over interprovincial sales. Interruptible transactions between provinces therefore are not expected to increase over current levels with the following exceptions:

- In Newfoundland, we assume that any electricity produced at the projected Gull Island hydroelectric power plant in Labrador which is surplus to Newfoundland requirements will be sold to Quebec; this will require that the two provinces reach a suitable accord in this regard;

- Alberta is increasingly interested in finding new markets for its coal-based electricity. The potential exists for future expanded trade with the U.S., either in cooperation with British Columbia or alone through new interconnections. We project that up to 2500 gigawatt hours of coal-based energy from Alberta will flow to British Columbia to serve domestic and/or export requirements; these transfers may increase if exports by British Columbia are greater than we have projected.

Total Interprovincial Trade

In 1989 total gross interprovincial trade, including firm and interruptible sales, was 36.2 terawatt hours. With the projected future sales by Manitoba to Ontario and from Labrador to Quebec, we estimate that total gross interprovincial trade will increase to 44.1 terawatt hours in the year 2000 and to 50.5 terawatt hours by 2010.

5.5 Implications for National Capacity Additions and Energy Resource Requirements

The implications of our provincial analysis of the evolution of national generating capacity are summarized in table 5-16 and figure 5-6. The capacity available to meet peak loads is projected to grow from about 103.7 gigawatts in 1989 to about 121.3 gigawatts in 2000.[1] By 2010, total capacity increases further to about 140.8 gigawatts.

Although our projections of annual demand increases are relatively low, averaging about 1.3 percent per year, in absolute terms this represents an average incremental capacity requirement of almost 1.2 gigawatts per year. In Quebec and Ontario requirements increase at the rate of about one Darlington type nuclear unit (880 megawatts) every two and three years respectively by the end of the study period. As noted earlier, we have projected a lower overall growth in electricity demand than the corresponding demand projections by provincial utilities. As a result, there generally is a deferral of generating plant additions relative to the utilities' generating expansion programs.

In 1989, hydro power accounted for about 60 percent of total Canadian generation, nuclear for about 15 percent, and fossil fuels, mainly coal, for the remaining 25 percent. We expect that hydro will continue providing the major share of total electricity production and capacity although coal will continue to be the major source in some provinces (Figure 5-7). Total Canadian energy

1 Note that this capacity includes reserve credits from interconnections which can be used to meet peak load requirements.

Table 5-16

Supply and Demand of Electricity in Canada

	1989	2000	2010
Generating Capacity (MW)[a]	103719	121265	140847
Domestic Peak Demand[b]	82489	92692	107257
System Peak Demand[c]	88933	101509	118956
Remaining Capacity	14786	19756	21891
Percent of System Peak	17	19	18
Generating Capacity by Fuel Type [MW][d]			
Hydro	57470	66275	78602
Coal	16954	18793	20018
Nuclear	11229	14528	16560
Oil	5502	5521	5654
Natural Gas	2522	2779	2845
Other	3516	5231	6798
Energy Production (TW.h)	483	585	671
Hydro	288	359	411
Coal	86	96	114
Nuclear	75	105	113
Oil	17	9	13
Natural Gas	14	12	16
Other	3	4	4
Domestic Consumption (TW.h)	**473**	**543**	**630**
Gross Exports	**18.5**	**45.3**	**46.8**

Notes: The numbers in this table have been rounded.

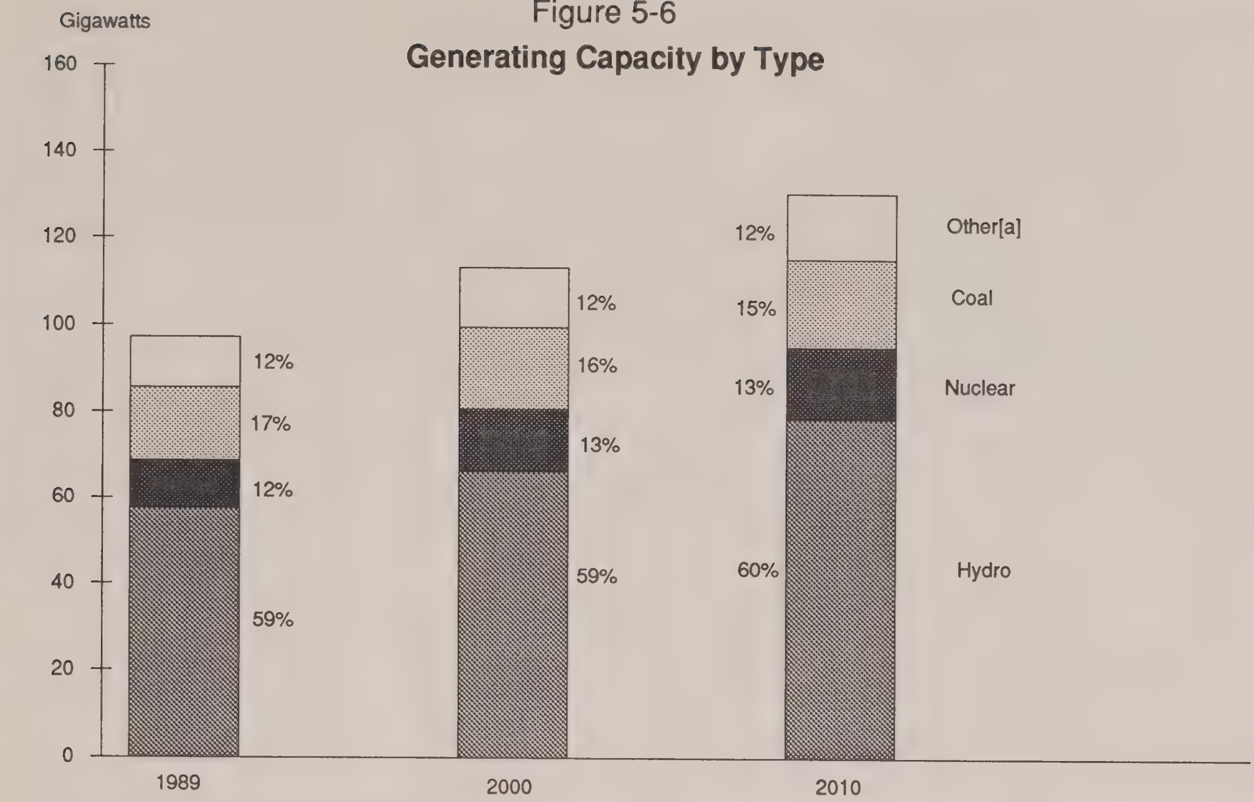
[a] Generating capacity in this table includes purchased capacity.

[b] These numbers are the sum of provincial peak demands, which are not necessarily coincident peaks. To this extent, remaining capacity and percent of system peak values may be understated on a national basis.

[c] System Peak Demand total includes Domestic Peak Demand amount for Newfoundland rather than system peak demand because of a large sales component to Quebec which would otherwise be double counted.

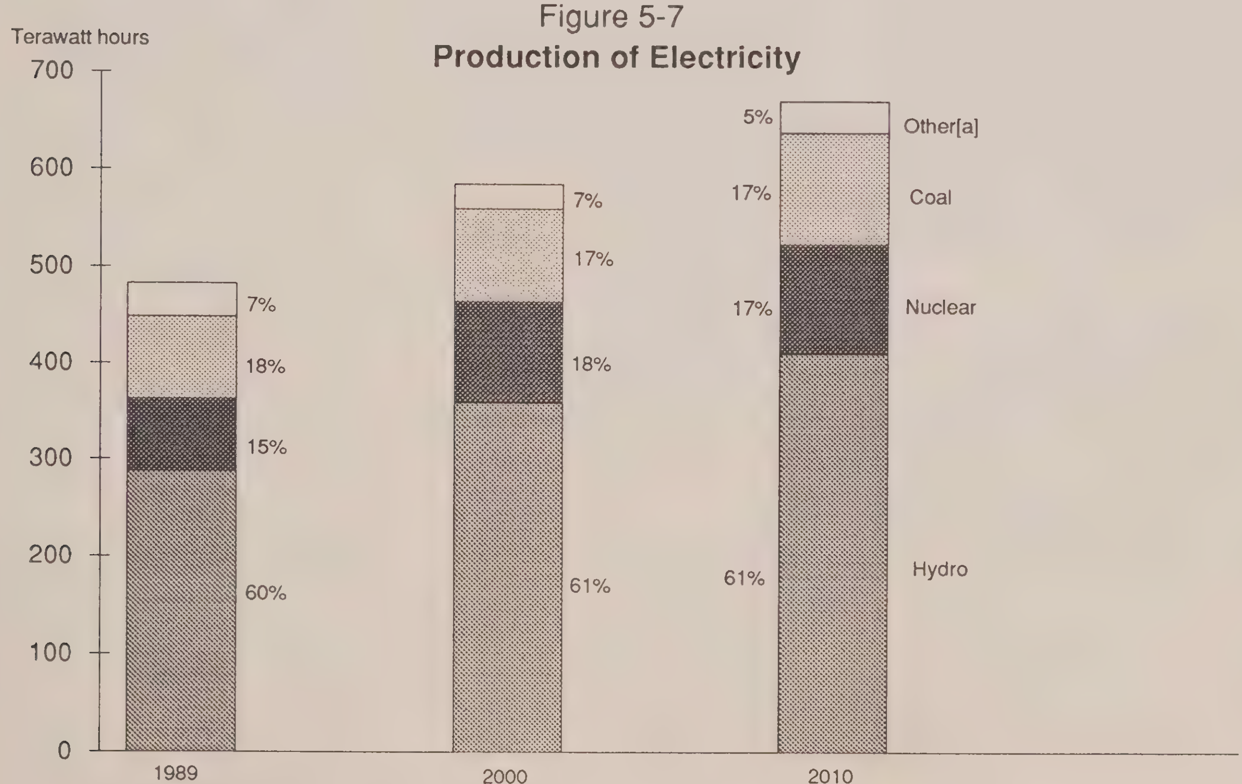
[d] Note that this excludes purchased capacity.

Figure 5-6
Generating Capacity by Type



Note: [a] Includes mainly oil and natural gas.

Figure 5-7
Production of Electricity



Note:[a] Includes mainly oil and natural gas

production was 483.8 terawatt hours in 1989. It is projected to grow to 687.5 terawatt hours in 2010.

Hydroelectricity

In 1989, hydro plants generated 287.7 terawatt hours, or about 59 percent of total production. By 2010, this source is anticipated to increase to 412.4 terawatt hours, about 60 percent of total electricity produced. This is equivalent to some 1485[1] petajoules of primary energy using the energy output method.[2]

Coal

In 1989, about 85.6 terawatt hours of electricity were generated from coal. This was about 18 percent of the electricity produced in Canada. In order to generate this electricity 966 petajoules of energy from coal were consumed.

We project that the amount of coal-generated electricity will decrease into the early 1990s and will increase thereafter to 123.5 terawatt hours by the year 2010. This represents about 18 percent of the total electricity produced in 2010. To generate this electricity about 1350[1] petajoules of energy from coal would be required in 2010.

Uranium

The amount of electricity generated at nuclear plants was about 75.4 terawatt hours in 1989, about 16 percent of the total electricity produced. The primary energy contained in the uranium used to produce this electricity corresponds to about 912 petajoules.

We expect nuclear-generated electricity to grow to about 113.3 terawatt hours in the year 2010. This represents about 17 percent of the total electricity production in 2010 and it would require about 1371 petajoules of energy from uranium.[3]

Oil

Oil-fired generation was concentrated principally in the Maritime provinces. Following the oil crisis of the 1970s a concerted effort was launched to convert many of these plants to coal. As a result, by 1989 only about 16.9 terawatt hours was generated from oil, about 4 percent of the total. The total amount of energy from oil used to generate this electricity was about 177[1] petajoules.

We project that the amount of electricity produced from oil fired plants will decrease to 13.6 terawatt hours by 2010. This corresponds to about 2 percent of the total electricity expected to be generated in 2010 and would require about 137[1] petajoules of energy from oil.

Natural Gas

In 1989, natural gas was used to generate 14.9 terawatt hours of electricity, about 3 percent of the electricity produced. This required about 146[1] petajoules of energy from natural gas.

We anticipate that natural gas will account for 20.3 terawatt hours of electricity or about 3 percent of total electricity production in 2010. About 177[1] petajoules of energy from natural gas would be required for electricity generation.

Gas-fired generating capacity is projected to more than double by 2010, from its 1989 level of about 3.2 GW, while gas-fired electricity production increases less rapidly. This is because gas-fired units are not assumed to be used for base load purposes.

Other

Electricity generated by other sources amounts to less than 1 percent of total annual generation throughout the period under review. This category includes hog fuel, pulping liquor, coke oven and

---

1 These numbers reflect our views on the fuels used to generate electricity; they include all the fuels required to meet electricity demand including the "unserved energy" component of the demand, which is an inherent part of any probabilistic energy production model. These final numbers are slightly different than those used in other chapters and related appendix tables which do not incorporate the above mentioned adjustment.

2 Since no fuels are used to generate hydroelectricity, there are two ways of calculating the primary energy associated with hydro power.
- We can define its primary energy as the energy produced at the dam site. Measured in this way the primary energy associated with the production of hydroelectricity would be equal to the energy content of the electricity output, 3.6 petajoules per terawatt hour. For convenience we label this the energy output method.
- A second method is frequently used, particularly when comparisons are being made of energy use across countries. This method (labelled the fossil fuel equivalence method) assumes that the amount of primary energy associated with hydroelectricity is the amount which would be required if fossil fuels were used. Using this method a conversion factor of 10.5 petajoules per terawatt hour is adopted because methods of generation using fossil fuels have, on average, an efficiency of about 33 percent. The use of the second method implies that the amount of primary energy attributed to hydro will be much larger than the amount of electrical energy produced. It is however, not relevant for Canada; we have large hydro resources and will not replace our hydroelectricity with electricity generated from fossil fuels. We therefore use the energy output method in this report.

3 Nuclear electricity is converted to petajoules using a factor of 12.1 petajoules per terawatt hour.

blast furnace gas, other biomass and fossil fuel by-product sources, wind and solar power. While these resources will grow in use over the study period, their overall contribution to energy generation is expected to remain small, except in isolated regions where their contribution may be important.

5.6 Concluding Comments

Our projections of the expansion of electricity generating capacity are driven by our analysis of the prospects for electricity demand growth. The prospects for growth in demand depend, in turn, on the rate and characteristics of economic growth, on energy prices and the relationships among prices of competing sources of energy, on the extent of technological change and on the rate at which new technologies are adopted.

Our analysis of these variables leads us to conclude that, on average over the study period, the rate of growth in electrical energy demand will be modest; about 1.5 percent per year. As noted, considerable uncertainty surrounds this estimate. Other analysts, including many provincial utilities, project domestic growth in electricity demand to be considerably higher. Higher rates of growth in domestic demand and in firm exports of electricity would result in requirements for correspondingly larger increments in electricity generating capacity earlier in the study period.

Based on commitments already made, on our assessment of utility plans and of U.S. markets, we see firm exports of electricity rising from the 1990 level of 16.5 terawatt hours to about 47 terawatt hours in 2010. In addition to firm exports, electricity is also exported on an interruptible basis depending on the relationship between generating capacity on the one hand, and domestic and firm export demand on the other.

Our analysis suggests that the pattern of interruptible trade will, in the near term revert to the pattern of the mid- to late-1980s as increasing generating capacity and a return to more normal levels of precipitation result in a decline in interruptible imports to Canada and an increase in interruptible exports. Over the long run, export trade is likely to consist increasingly of firm exports.

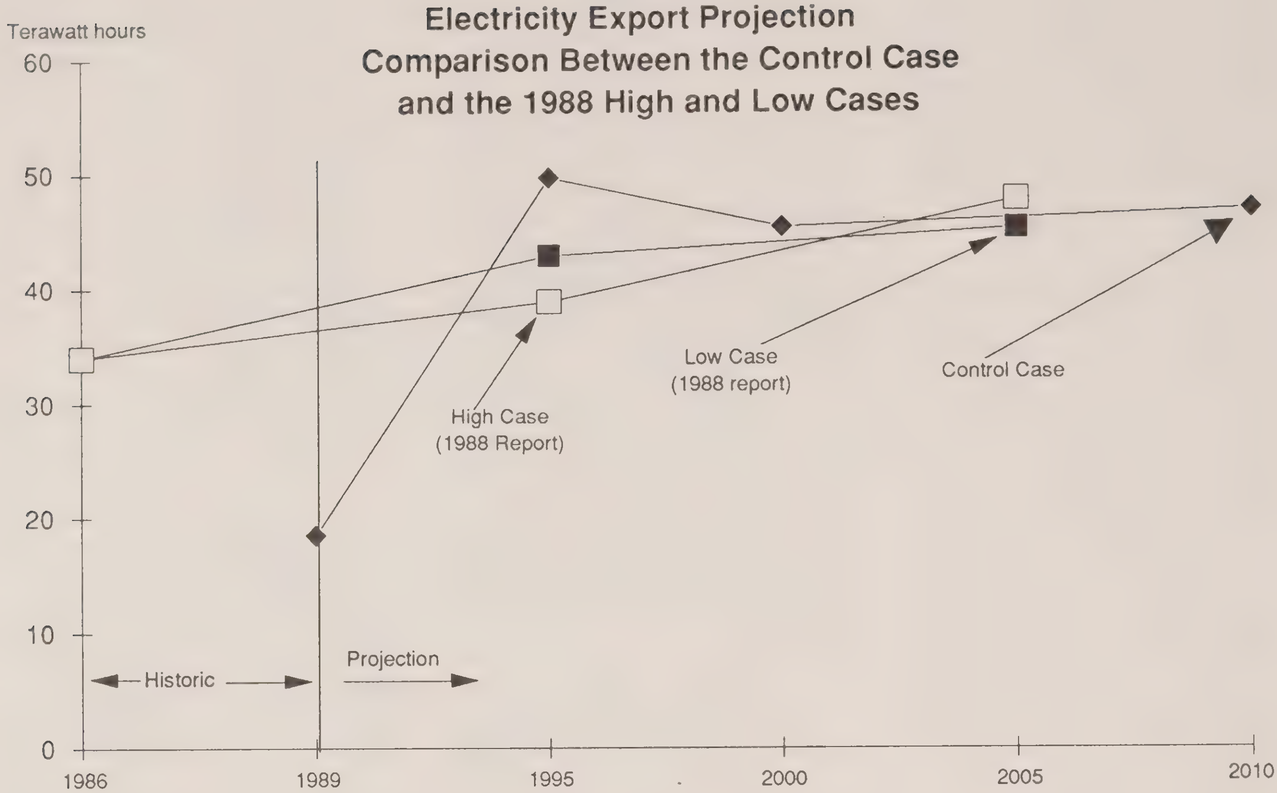
The electricity export projections in our Control Case are compared with those in our 1988 report in Figure 5-8.

- The starting points of the export projections between the two reports are quite different. In the years prior to 1988, precipitation patterns had been generally normal and the high export levels in 1986 (the last year of historical data in the 1988 report) reflected hydro-generated exports particularly from Quebec, Manitoba and British Columbia. By 1989, many regions in Canada had experienced severe dry weather for several years while domestic demands were increasing more rapidly than expected. The result was a significant downturn in export trade, especially from the predominantly hydraulic Canadian systems.
- For 1995, we now project that electricity exports will surpass the previously expected levels by a wide margin - 50 terawatt hours as compared with 35 and 42 terawatt hours for the 1988 high and low cases respectively. This is explained by the fact that, in the 1988 Report, our demand and supply projections closely matched those of the provincial utilities. In this study, however, our supply projections for the period to 1995 reflect the utilities' committed capacity additions, but our demand projections are generally lower. As a result, we now show larger surpluses of interruptible electricity available for export.
- For the period beyond 1995 the export profiles are similar, as we have not changed our view about the longer-term prospects for US/Canada trade in electricity.

Our review leads us to conclude that we will still need to rely on conventional sources of supply such as hydro, coal and nuclear capacity to meet the bulk of Canadian electricity demand over the study period despite growth in sources of generation such as IPPs and despite demand management programs. Notwithstanding our projection of relatively low load growth rates, the need for new facilities in the years to come implies substantial expansion in generation capacity, albeit more modest than that which the provincial utilities are planning.

Utilities today are influenced by many factors which make the generation planning process much more complex than it was just a few years ago. In some provinces, notably Ontario and British Columbia, public regulatory review processes have been undertaken or are now underway which have the objective of developing a set of provincial policies to guide and direct electric utilities to pursue generation supply options which are environmentally acceptable. This implies that provincial electric utilities must consider not only tra-

Figure 5-8
Electricity Export Projection Comparison Between the Control Case and the 1988 High and Low Cases



ditional supplies, large generating stations with high capital costs and long lead times, but also more flexible, less capital intensive and short lead time supplies and other novel ways of generating and conserving electricity. Considerable progress has been made in this direction through encouraging IPPs and by the adoption of demand management programs. To the extent those plans are known, we have included these initiatives in our projections of demand and supply.

As for interprovincial electricity trade, we see the initiatives by Manitoba to sell substantial quantities of electricity over a long term to Ontario, through the advancement of the Conawapa hydroelectric facility, and by New Brunswick to sell peaking capacity to Quebec through the construction of additional gas turbine capacity, as significant signs that some provinces have a growing interest in mutually beneficial interprovincial trade. This potential, combined with the possible contribution of IPPs, widens the range of supply options which utilities can pursue.

Though our projections assume that electric utilities' supply will be in place when needed to meet demand, there are uncertainties with respect to demand, supply and the eventual impacts of environmental concerns, which could affect the smooth matching of supply and demand.

On the demand side, making accurate projections is difficult because of the uncertainty about the variables which impact on demand such as economic activity; changes in technology, in consumers' choices and in energy policy; demand management programs; and incentive pricing arrangements. Underestimating the future demand for electricity can result in recourse to expensive short-term supply arrangements, while overestimation could lead to excess capacity.

On the supply side, identification of needed capacity resources for only five to six years into the future has become a more common practice because of the major uncertainties associated with the commitment of facilities requiring long lead times. This has two kinds of risks: first that utilities will not achieve the lowest long-run incremental cost of generation, and second that additional capacity may not be available when needed to maintain adequate reserve margins.

The generation plans of several provinces have undergone or are now undergoing environmental scrutiny including public hearings held by provincial agencies. In other instances, the applicable process of environmental review remains to be determined. This is, for example, the case in Quebec with respect to the Great-Whale hydroelectric development complex.

Environmental considerations associated with new electricity supplies can have an important impact not only on the timing of these developments but indeed on whether they will be developed at all. Environmental matters include a range of socio-economic factors as well as any physical impacts of development on the environment. For new hydraulic resources, the main environmental issues include impacts on the life styles of local populations and impacts on land use from flooding, on navigable waters, and on flora and fauna. For nuclear generation, the principal concerns relate to public safety and nuclear waste management. For coal-fired generation, the main concerns are air quality and global warming. Finally, for new transmission facilities, especially at high voltage levels, major concerns relate to health effects from electromagnetic fields and visual degradation of the countryside.

Chapter 6

Natural Gas

In this Chapter we first discuss our approach to natural gas price formation and flows. Next, our main input assumptions are set out. These relate to natural gas resources and supply costs in each of Canada and the U.S., the pipeline network and tolls, distribution margins, and U.S. and Canadian demand. We then discuss the results for the Control Case, including fieldgate prices, U.S. supply and demand, Canadian exports and imports, domestic demand and the various components of domestic natural gas supply. Finally, we outline the results of sensitivity tests conducted for oil prices, Canadian gas resources, North American gas resources and backstop costs.

6.1 Approach to Price Formation and Gas Flows

We develop our projections of natural gas prices on the premise that Canada participates in an open, integrated and competitive North American natural gas market, in which North American supply and demand conditions determine the prices of natural gas in Canada and in the U.S. Comparative delivered costs from different sources determine the flows from particular sources to destinations. A part of this flow pattern is the trade in natural gas across the Canada-U.S. boundary, comprising mainly but not exclusively Canada's natural gas exports to the U.S. The inter-regional distribution of these flows indicates the pipeline capacity which may be required over the longer term.

Figure 6-1 shows the basic logic of price determination and flow patterns, and it identifies the relevant factors which we discuss in this chapter.

On the **supply** side, a number of key assumptions determine the incremental unit cost of natural gas. Incremental costs depend upon the costs of factor inputs (e.g. labour and equipment for exploration, development and processing), and on the finding rate[1], which is in turn related to ultimate potential. In our work, we assume a range of ultimate potential estimates; for each one of them, we assume that as the resource is progressively depleted the finding rate declines, which causes supply costs to increase. This progression of declining finding rates and increasing cost is mitigated, but not eliminated, by ongoing technological progress which we account for in our supply cost estimates. The biggest component of exploration and development costs is the cost of drilling. The main financial variables are interest rates on debt, return on equity, and the debt:equity ratio. The reserves to production ratio influences the level of production costs; the higher it is, the more gas it is necessary to find per unit of production, and the higher the cost attributable to that production.

On the **demand** side, the market for gas depends mainly upon economic activity, demographic factors (e.g. household formation), fuel preferences (e.g. environmental fuel preference for electricity generation) and the prices of competing fuels (e.g. oil).[2] As the resource base is progressively depleted at a rate determined by cumulative consumption, the gas supply cost increases, which means that gas will be produced only if wellhead prices increase to accommodate these increasing costs.

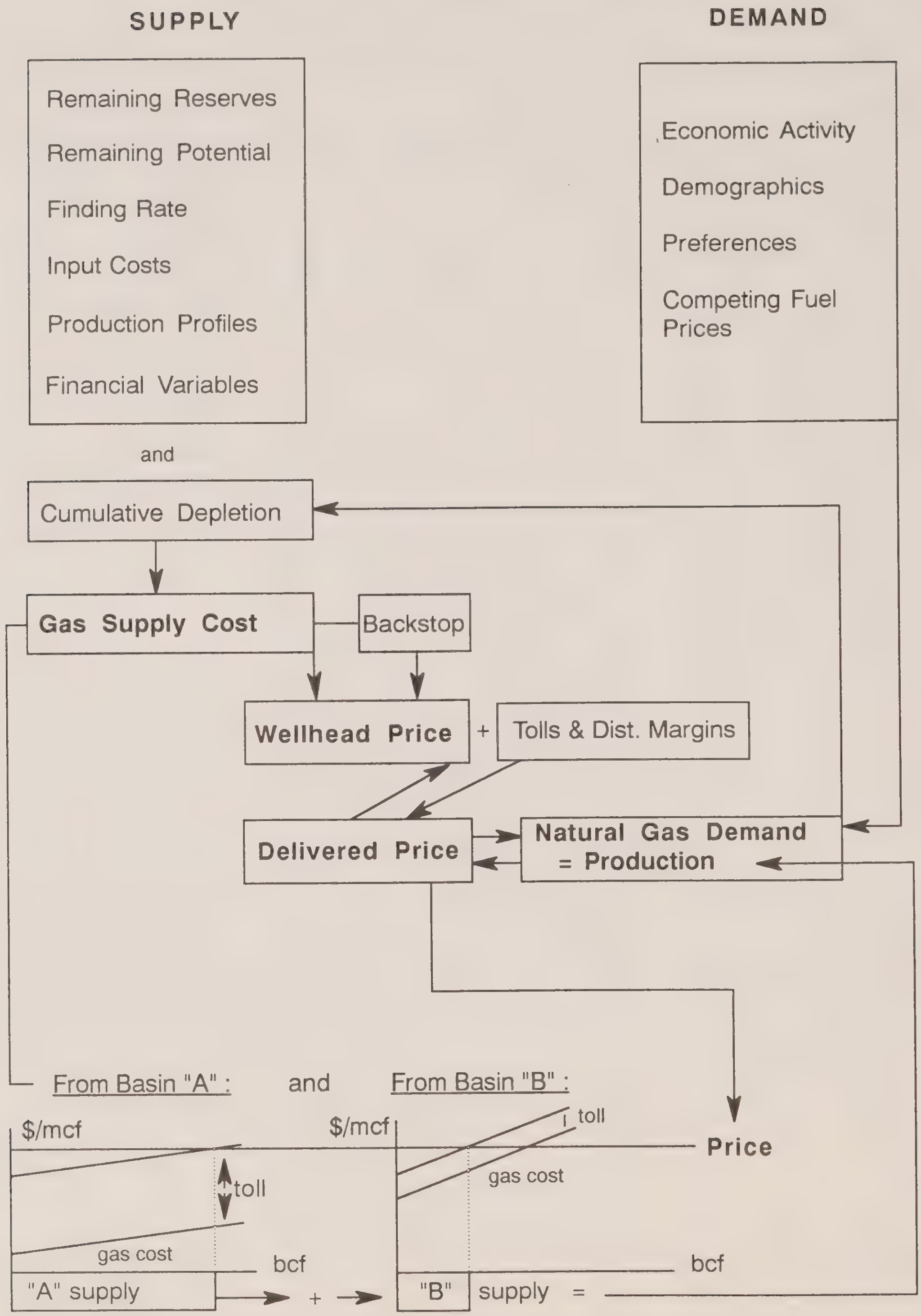
One key objective of our analysis is to find paths of natural gas prices over time, which will balance supply and demand given assumptions about the more important underlying supply and demand conditions. The value of natural gas is different for different users, depending partly on the cost of their alternative fuel options, which differ between users. Because of this, all else equal, aggregate volumes consumed will increase as natural gas prices decrease and vice versa. In principle, there is an amount that would be consumed at a price which is just high enough to elicit the corresponding amount of production. This price is generally

1 The finding rate is the amount of gas discovered per metre of drilling.

2 For Canada, we discussed these factors in previous chapters. We also require demand assumptions for the U.S. market, and we discuss those in this chapter.

Figure 6-1

North American Natural Gas Market Analysis



Relative gas costs between basins and tolls from those basins to a market determine the share of each basin to that market and pipeline flow pattern .

called the "equilibrium price" because it is at a level which causes quantities produced and consumed to be the same. This equilibrium price is found by an iterative process which successively finds prices that narrow the difference between volumes demanded and supplied, until the market settles on a price at which the demand and supply volumes are about the same. The equilibrium price which the end user pays differs from that which the producer receives because of transportation and distribution costs incurred in moving the gas from the wellhead to the end user.

There is a special feature of the natural gas industry which plays some role in gas price formation: most analysts believe that conventional natural gas is a depletable resource, the cost of which will increase with cumulative consumption, up to a price level at which gas from another source or some other close substitute can be made available in very large amounts relative to consumption. This fuel is called the "backstop resource". The value of the backstop resource influences wellhead prices over all time periods in the projection, to the extent that resource owners know and take future value into account in today's pricing and output decisions.

They do this by adjusting the amount they will supply to the market such that there will be just enough revenue between the market price and the direct supply cost to compensate them in present value terms for making the gas available now rather than holding it in the ground till it gains more value later on. This surplus is commonly known as a "depletion premium" or a "user cost". We use the latter term. The cost of the backstop, the time to exhaustion, the discount rate used for bringing future value to present value and the size of the market are the key factors determining the user cost. This approach to price formation requires that resource owners in aggregate know these values far into the future (notwithstanding that different analysts' estimates of ultimate potential and backstop values differ substantially). The user cost, combined with direct production costs (the level of which at any time results from cumulative consumption up to that time) determines the market price. (We provide a more detailed discussion of the relationship between user cost and price formation in Annex 1).

If royalties were set on the basis of the foregoing principles, the royalty would be the user cost, appropriated by the resource owner (in Canada mainly the provincial governments), while the producer would earn a normal rate of return on investment, which is part of direct supply cost.

This view of the price formation process is controversial. There is a body of opinion which argues that the whole theory of price formation based on depletable resources and foresight of future value is fundamentally flawed. The key elements of this critique are:

- the economic depletion of the natural gas resource is so far into the future that backstop considerations have very little present value;
- there is wholly inadequate evidence upon which to estimate with confidence the future costs of either natural gas or the backstop resource;
- because of this, resource owners do not know future resource values, costs and market conditions; therefore inter-temporal optimization of how much to supply at any one time is impossible; and
- there are technical and institutional constraints which prevent producers from adjusting their supply to an economically optimal level per time period, even if they knew how to do so.

Those who support this critique would find it more realistic to portray resource owners and producers as making investment and production decisions based on a much shorter time horizon, uncertain information and other factors which the exhaustible resource/accurate foresight approach does not take into account for price determination.

While these arguments may have merit, they do not invalidate using an analytical framework which portrays rational market behaviour based on expectations about the exhaustibility and future value of energy resources. It would be just as extreme to argue that future expectations about market fundamentals do not enter into long-term supply development decisions and the design of royalty regimes, as it is to argue that they drive supply decisions.

For producers, investment in natural gas exploration and development, as for most other investment decisions, means incurring front-end costs in the expectation of future returns. For many producers, this not only involves decisions about whether to invest in particular plays, but also a more general, longer-term commitment to the industry. These commitments normally involve careful assessment of opportunities and risks, which necessitates devel-

oping some perspective on future costs and benefits. Furthermore, even for "gas in the ground", producers do defer some sales today, in the expectation of greater present-value returns from some other sales prospect tomorrow. In short, we believe that in general producers make decisions in their economic interest, taking account of future expectations.

It is also reasonable to expect that producing-province governments exercise some foresight in how they set royalties, because they perceive that natural gas is both a depletable resource and an important component of their economic assets. The rate at which they tax it influences producer netbacks, how much of it gets depleted now, what will be left for consumption tomorrow, and how much revenue they will be able to earn tomorrow from remaining resources. We believe that governments generally understand that supply and demand influence price, that taxation influences supply and demand, and that there is "time value" to the sale of assets.

Granted that the future matters to both resource owners and producers, it is much less clear what the length of that time horizon is for different players, how they value it, how good their judgement can be about future oil and gas values, and what other factors (for example, short-term cash flow needs or defence of market share) may influence their taxation and production decisions. At present, our analytical frameworks are heavily stylized at the extremes in portraying either quite timeless economic behaviour on the one hand, or rational behaviour based on accurate foresight far into the future on the other hand. The reality, as we said above, is probably somewhere in between. We have chosen to portray this reality using a framework which assumes resource exhaustibility and accounts for future value, because it has the merit of taking into account certain longer-term decision variables which appear to influence gas market behaviour.

The approach integrates into one behavioural framework many strands of current energy market policy and analysis, for example: the current policy framework is to generally let the market determine supply, demand and price; most industry analysts subscribe to the view that the natural gas resource has identifiable economic limits in the long term - though estimates vary widely - and they do produce long-term projections of oil and gas prices which incorporate long-term views of supply costs and market values. An analytical framework which embodies these principles is appealing if used with caution - a point to which we return below.

We mentioned above that alternative fuel prices influence the demand for natural gas. They also influence the price of gas through their impact on the demand for gas. Some observers of energy markets suggest that the oil price determines the natural gas price on a \$/Btu-parity basis such that, for example, when oil prices decline, gas prices must decline similarly, otherwise gas would lose market share. The underlying reasoning is that a considerable portion of the natural gas market is switchable between oil and gas, especially in the U.S.

The price of oil does influence the price of gas, but the price changes of the two fuels, or their actual price levels need not be equivalent, because:

- supply and demand conditions on the two fuel markets are not necessarily the same, either in the short run or in the long run;
- contractual arrangements may lend less flexibility to many gas price arrangements than is usually the case for oil, which is traded on a very short-term basis; and
- when the oil price changes, gas prices may not change to the same extent; it depends upon how much demand is switchable to oil over what price range (and over what time period) and to what extent gas supply cost conditions allow producers and resource owners to meet different oil prices and maximize their returns.

We provide a more technical exposition of this matter in Annex 2.

In addition to these general principles of price determination, the natural gas industry has special characteristics which must be taken into account if the analysis is to provide useful insight into how gas markets may evolve, for example:

- producing and consuming regions are spread across the continent and the different regions have different supply and demand characteristics; and
- the costs of transportation differ between the various sending and receiving points.

A key function of a competitive market's economic behaviour, and an objective of our projections, is to find levels of demand and supply and flow patterns which maximize returns to the resource owner while minimizing costs to the consumer, for any given set of underlying assumptions.

The lower portion of Figure 6-1 indicates how sourcing and flow patterns are determined in order to achieve this objective. In this two basin illustration, at the price level shown, Basin "A" supplies the market with much more gas than does Basin B because Basin A's delivered cost is lower. In this illustration, A's gas costs are so much lower than B's that it can withstand the much higher tolls necessary for its gas to reach the market compared with B's; hence its larger market share. Neither A nor B are better off by supplying more or less than they do in this example. Consumers are "best-off" with this sourcing pattern, insofar as the price would have to be higher if they took more from B and less from A than shown in Figure 6-1.

The North American natural gas market is very complex - there are many supply and demand regions and many pipelines which connect them. Each of these regions and pipelines has its own physical and economic attributes. Hence, any aggregate analysis of this market which uses enough regional detail for the analysis to be realistic requires integrating a very large amount of data into a coherent behavioural framework. Otherwise, it simply is not possible to develop a *coherently integrated* set of projections linking demands, supplies, flows and prices. We do this by using the Decision Focus Inc. "North American Regional Gas" model (NARG), and other NEB supply and demand models. A picture of the NARG's gas network is presented in Figure 6-2.

The main usefulness of NARG for present purposes is that it provides us with a broad, long-term integrated picture of how North American gas flows and prices could evolve, given the assumptions we make about supply and demand conditions in each regional market, pipeline tolls, and the model's own behavioural basis: that of competitive markets working to maximize returns to the resource owner while minimizing costs to consumers within any given set of basic assumptions. The NARG embodies the exhaustible resource/producer foresight assumptions discussed above. It has the unique advantage of incorporating a great deal of regional information on supply and supply costs, pipeline tolls and capacities, and demand conditions into one internally consistent analytical framework which explicitly integrates the Canadian and U.S. markets.

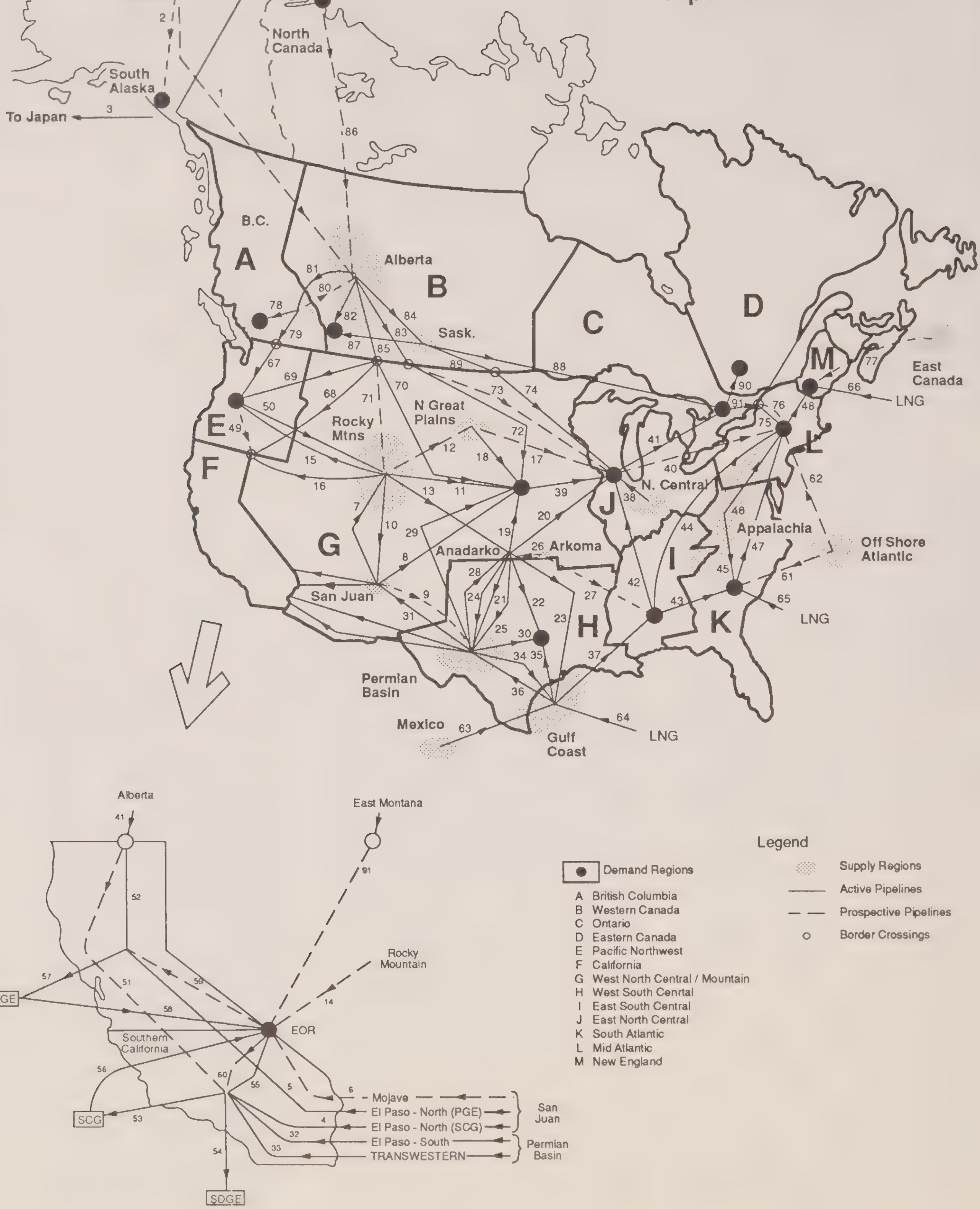
All such models simplify and stylize the complex world they portray. Because of this, and because of the uncertainty about many of the assumptions needed to operate such a model, neither this model, nor any other we know of in this field, provides "the right answer". It does provide an indicative understanding of the directions in which the market may move, given our assumptions. The NEB's other models provide considerably more detail on Canadian supply and demand matters than is available from NARG; hence, we use NARG to develop the overall North American market analysis - especially prices and inter-regional flows over time. Given wellhead price and export information from NARG, we use the Board's other models and informed judgement based on consultation with market participants, in order to produce a more detailed picture of Canadian supply and demand.

We deal with uncertainty by developing a range of results, based on alternative values for those assumptions that are both uncertain and have considerable impact on those results of greatest interest in this report. Oil prices and the size and supply cost of the natural gas resource are the main assumptions which we test. There are others worthwhile testing (such as certain pipeline tolls and different backstop costs) which time and space do not allow us to develop here in a comprehensive manner.

We deal with the consequences of stylized model behaviour by looking at the results for which we have some alternative information - especially over the next several years, and we exercise judgement as to whether the model results are reasonable in light of other commercial information. As there is usually a range of plausible values for most input assumptions, we adjust the input assumptions and modify the model results judgmentally as we consider appropriate.

While we consider it necessary to show the Control Case results in some detail to provide an anchor point for developing the range of values around it, we must emphasize that we do not regard the Control Case as a "most likely" outcome. It is only an anchor in a range, which we present in some detail for the convenience of readers who wish to have at least one set of detailed information. Indeed, during our consultations, and in the analytical work leading up to these results, we were struck by the diversity of opinion about many of the assumptions needed to do the analysis, and by the sensitivity of certain results to plausible differences in values describing certain supply sources or pipeline tolls. It is simply not practical within the confines of this document to report on all of the significant nuances we discovered in the progress of the work, so

Figure 6-2
North American Regional Gas Model Pipeline Network



even the ranges we present here are not exhaustive.

To conclude this section on our approach, we recapitulate several key points:

- North American supply and demand conditions including prices of alternative fuels determine natural gas prices across the continent. Because such a large proportion of total demand and supply occurs in the U.S., U.S. market conditions have a major effect on price formation in Canada.

- In general, the most important factors determining natural gas prices are assumptions about ultimate potential, backstop costs, the shape of the cost curves, oil prices, factors determining demand, and the rate at which cumulative North American consumption causes gas supply costs to increase.

- The size of Canada's exports to the U.S. depends upon competitive conditions (comparative supply costs and pipeline tolls) which Canadian gas faces in the various regional markets to which it may be delivered in competition with U.S. gas. Canadian exports do not directly determine Canadian natural gas prices. Rather, it is North American supply and demand conditions which determine both exports and prices.

- Our analytical framework operates on the basic presumption that markets work competitively, and that regulation does not fundamentally alter market outcomes. This approach is consistent with the basic energy policies and regulatory practices in both Canada and the U.S.

- There is considerable uncertainty about most of the variables which influence the results, hence it is appropriate to treat these results as indicative, and to focus on the ranges indicated by the sensitivity tests, rather than on the Control Case alone.

- There is debate about the realism of models which estimate supply, demand and price assuming accurate foresight of long-term scarcity values. Nonetheless, we consider the framework useful, accompanied by consultations with market participants and informed judgement.

6.2 Input Assumptions

In the previous section, we described our approach to projecting natural gas prices and interregional gas flows. In this section we discuss the input assumptions which underlie our North American natural gas market analysis.

We begin the discussion of input assumptions with a description of Canadian natural gas resources and related supply costs. We then discuss U.S. natural gas resources and supply costs and provide a comparison to those which are being used for Canada. Next we describe the pipeline network, pipeline toll and distribution cost assumptions which we have used for the North American natural gas market projections. We then discuss how oil prices and constraints on the use of oil for environmental reasons influence the natural gas market. Finally, we conclude this section with a description of the initial estimates of U.S. and Canadian demand which must be input to the NARG model in order to develop natural gas price, supply and demand projections.

6.2.1 Canadian Resources

The Canadian natural gas resource base encompasses all in-place volumes of natural gas, discovered and undiscovered and conventional as well as unconventional.[1] For purposes of the analysis in this report, we will focus on that portion of the resource base which is estimated at this point in time to be ultimately recoverable, or the ultimate recoverable resource potential. Estimates of the related gas-in-place are provided for comparative purposes. The future natural gas supply will be obtained from this resource base and its size, geographical location and other characteristics are important considerations with respect to the supply projections which are provided later in this chapter.

Conventional natural gas can be technically and economically recovered using normal production practices. For conventional natural gas, recovery of 70 to 90 percent of the gas-in-place can generally be anticipated.

Unconventional natural gas resources differ from conventional resources in that they are more

1 The terminology related to the classification of resources and reserves is not consistently agreed upon or applied by those who make reference to these estimates. For purposes of this report, we have attempted to use terminology which is generally recognized and accepted by industry and governments in Canada. However, we recognize that there may be those who disagree with the classification terminology that we have used in this report. The reader is cautioned to closely examine the definitions provided in the text and in the appended glossary.

difficult to recover and require the application of specialized recovery techniques. Included in this category is natural gas contained in very low permeability, or "tight", reservoirs and natural gas contained in coal formations, which is generally referred to as coalbed methane.

Figure 6-3 depicts the location of significant current and anticipated natural gas supply sources in North America. Table 6-1 summarizes Canadian conventional natural gas resources by component and by province and territory. The estimates of ultimate recoverable resource potential in this table are broadly divided into discovered and undiscovered recoverable resources. These are estimates at a point in time which may be revised periodically, as production continues, new discoveries are made, other discovered resources are converted to reserves and our overall understanding of the size, location and characteristics of the resource improves.

In sections 6.2.1.1, 6.2.1.2 and 6.2.1.3 we discuss the specific components of the conventional ultimate recoverable resource potential, consistent with the presentation of Table 6-1. In section 6.2.1.4 we describe the unconventional natural gas resources considered in our analysis.

Table 6-1
Conventional Natural Gas Resource Estimates at Year End 1989
[EJ]

	Discovered Recoverable Resources					
	Cumulative Production	Remaining Established Reserves	Other Discovered Resources	Total	Undiscovered Recoverable Resources	Ultimate Recoverable Resource Potential
British Columbia Onshore	8.2	8.1	0.0	16.2	24	40
British Columbia Offshore	0.0	0.0	0.0	0.0	10	10
Alberta	59.6	62.6	0.0	122.3	78	200
Saskatchewan	2.0	2.7	0.0	4.7	3	8
Manitoba	0.0	0.0	0.0	0.0	0	0
Ontario	1.2	0.4	0.0	1.6	0	2
Nova Scotia Offshore	0.0	0.0	6.3	6.3	19	26
Newfoundland Offshore	0.0	0.0	5.7	5.7	58	63
Mainland Territories	0.3	0.3	0.3	0.8	11	12
Mackenzie Delta & Beaufort Sea	0.0	11.9	0.5	12.4	61	74
Arctic Islds. & E. Arctic Offshore	0.0	0.0	16.0	16.0	105	122
Other Areas (a)	0.0	0.0	0.0	0.0	3	3
Total	71.2	86.0	28.9	186.1	374	560

Sources:
NEB and Provincial Agencies for estimates of resources in conventional producing areas.
COGLA Annual Report, 1989 for estimates of resources in the Frontier Regions.

Notes:
Numbers may not add due to rounding.
(a)GSC resource estimates for Hudson Bay and the St. Lawrence Lowlands.

Figure 6-3
Location of NARG Natural Gas Supply Regions

6.2.1.1 Discovered Recoverable Conventional Resources

Discovered recoverable conventional resources are those which are estimated at a point in time to be recoverable from known accumulations (that is accumulations which have been shown to exist by drilling, testing or production) using known technology. These resources total some 4800 billion cubic metres (186 EJ) of conventional natural gas as of year-end 1989. Included in this category are cumulative production, remaining established reserves and other discovered recoverable resources, each of which is discussed in the following sections.

Cumulative Production

Cumulative production of natural gas amounts to about 1850 billion cubic metres (71 EJ) as of year-end 1989, about 38 percent of the conventional recoverable natural gas resource discovered to date.

Remaining Established Reserves

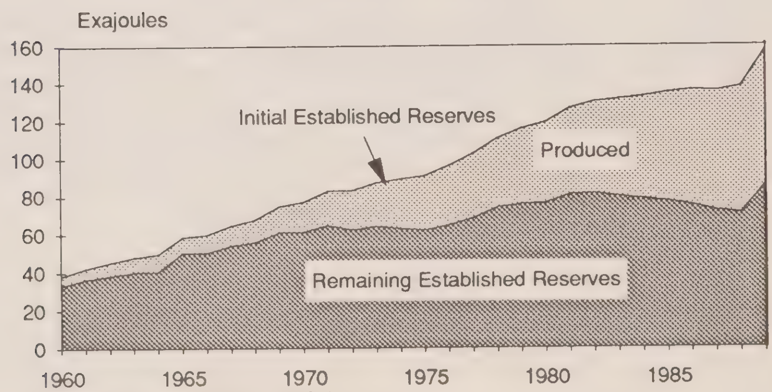
Established reserves are that part of the discovered recoverable resource base that is estimated at a point in time to be economically recoverable using known technology under present and anticipated economic conditions. Those established reserves not yet produced are termed remaining established reserves. Initial established reserves are the sum of remaining established reserves and cumulative production.

Estimates of established reserves of natural gas are compiled from assessments of individual pools by Board staff, industry studies and estimates from provincial agencies.

We estimate the remaining established reserves of natural gas as of 31 December 1989 at 2234 billion cubic metres (86 EJ). Historical data is summarized in Appendix Table A6-1. These reserves are located primarily in Western Canada and in the Mackenzie Delta/Beaufort Sea region. Alberta reserves comprise 73 percent of Canada's remaining established natural gas reserves, B.C. 9 percent and Saskatchewan 3 percent. The Board recognizes 309 billion cubic metres (12 EJ) of established reserves in the Mackenzie Delta/Beaufort Sea region, primarily in onshore and shallow offshore areas.

Figure 6-4 shows that remaining established reserves of natural gas have generally declined since the early 1980s, except in 1989 when reserves were first recognized for the Mackenzie Delta/Beaufort Sea region. Annual production has generally more than offset reserves additions over this period, as drilling activity has declined significantly from the peak levels achieved in the late 1970s and early 1980s due to the surplus supply situation and decline in prices.

Figure 6-4
Established Reserves of Marketable Natural Gas



Source: Appendix Table A6-1

Other Discovered Recoverable Conventional Resources

The discovered recoverable conventional resources that are included in this category are those that are estimated at a point in time to be recoverable using known technology but have not yet been recognized as established reserves because of uncertain economic viability.

These resources are located entirely in the frontier regions. We have adopted the discovered recoverable resource estimates published by the Canada Oil and Gas Lands Administration (COGLA) at year-end 1989 and adjusted these estimates by the amounts included by the Board in established reserves. Discovered recoverable resources in the frontier regions could be classified as established reserves in the future as the development timing and economics become more certain.

Resources in this category total 750 billion cubic metres (29 EJ), or about 16 percent of the total discovered recoverable resource. Of this total 165 billion cubic metres (6 EJ) are located offshore Nova Scotia, 149 billion cubic metres (5 EJ) offshore Newfoundland and 416 billion cubic metres (16 EJ) in the Arctic Islands.

6.2.1.2 Undiscovered Recoverable Conventional Resources

Undiscovered recoverable conventional resources are those that are estimated at a point in time to be recoverable using conventional technology from accumulations that are believed to exist on the basis of available geological and geophysical evidence but have not yet been shown to exist by drilling, testing or production. The estimates are based on the application of known technology under current and anticipated economic conditions. Both extensions to currently established pools and new discoveries are included in this category.

Estimates of undiscovered recoverable resources are highly uncertain and can be expected to have a wide range, although the range should narrow over time as geological and geophysical data are accumulated through ongoing exploration. The estimates can change considerably over time as new technologies are developed and geological knowledge increases.

In establishing a plausible range of estimates of undiscovered recoverable conventional natural gas resources for Western Canada we considered a number of sources, including:

- input obtained during the consultation process from industry representatives and governments;
- estimates of natural gas resources of the WCSB published by the Geological Survey of Canada, which are based on a rigorous geological and statistical examination of the Basin (the GSC uses a statistical probability approach for its analysis and expresses its estimates as a range with associated probabilities of occurrence)[1] ; and
- our own analysis, which is primarily based on a statistical extrapolation of historical trends in reserves additions.

The analysis in our 1988 Report was based on the GSC's estimate of natural gas resources published in 1983.[2] However, the data and analytical work upon which this study was based is now approximately a decade old. Although the GSC is updating the study, the results are not yet available. The ERCB is also conducting a study of remaining natural gas potential in Alberta but its study is also not yet complete.

An extremely wide range of estimates of undiscovered recoverable conventional resources for the WCSB was provided by industry and government representatives during our consultations. The diversity in these estimates, in our view, reflects the difficulty in conducting an aggregate assessment of this nature that is supported by thorough geological, engineering and economic analysis. Most of the input we received, while undoubtedly based on the best judgement of the parties consulted, did not appear to be supported by extensive analytical work and it would appear that there is a need for an updated and improved assessment of Canada's undiscovered natural gas resources.

Given the evident uncertainty regarding these estimates and the lack of a current comprehensive technical assessment of the undiscovered conventional natural gas resources in Western Canada, we have had to use considerable judgement in deciding upon the

1 The GSC estimates do not include an allowance for further extensions. We have made a small adjustment to the available GSC estimates to account for this. We used CPA historical data to estimate growth rates for extensions. These growth rates were then applied to CPA's initial established reserves by year of discovery to obtain an estimate of the future growth of these reserves.

2 R.M. Proctor, G.C. Taylor and J.A. Wade, *Oil and Natural Gas Resources of Canada 1983*, Geological Survey of Canada Paper 83-31.

range of estimates to use in our analysis. For the Control Case, we have assumed undiscovered recoverable conventional resources for the WCSB totalling some 2700 billion cubic metres (105 EJ). For the low and high resource sensitivity cases we have used estimates of 1500 billion cubic metres (55 EJ) and 4000 billion cubic metres (155 EJ), respectively. The basis for the selection of this range is more fully described in section 6.2.1.3.

We have disaggregated the total estimate of the undiscovered recoverable resources of the WCSB from this study to the provincial level based on input received during the consultations and by assuming that the potential for new discoveries will be roughly proportional to initial established reserves. We have provided this breakdown because we consider it to be potentially useful for comparative purposes. However, this analysis is not supported by a rigorous geological review and therefore should be used with some caution.

For estimates of undiscovered recoverable conventional resources in the frontier regions, we have relied on estimates made by the GSC and published by the Canada Oil and Gas Lands Administration (COGLA).[1] Estimates of future discoveries are expressed as a range with associated probabilities of occurrence. When so expressed, we have used the "average expectation" for the specified range. The average expectation has a 50 percent probability of occurrence. Lower estimates than the average expectation have a higher probability of occurrence than 50 percent and higher estimates than the average expectation have a lower probability of occurrence. For the Control Case we have assumed the GSC's average expectation of undiscovered recoverable resources for the frontier regions. This estimate amounts to 7000 billion cubic metres (about 270 EJ). While we recognize that this estimate is highly uncertain, we have not considered high and low resource estimates for the frontier regions because, being generally high cost, they have very little impact on supply over the period of our projection.

Our estimate of total undiscovered recoverable conventional natural gas resources in both the WCSB and the frontier regions in the Control Case is 9715 billion cubic metres (375 EJ), about 28 percent of which is in the WCSB.

6.2.1.3 Ultimate Recoverable Conventional Resource Potential

The estimated ultimate recoverable conventional resource potential for Canada amounts to 14 550 billion cubic metres (560 EJ) for the Control Case. Of this total, approximately 250 EJ are located in Western Canada and essentially all of the remainder in the frontier regions.

As noted earlier, there are very diverse views regarding the Canadian ultimate recoverable conventional resource potential. We are using a range of estimates of ultimate recoverable conventional resource potential in the WCSB from 200 EJ to 300 EJ, with 250 EJ as the Control Case. Table 6-2 summarizes the range of estimates we are using for the WCSB in this report and compares them to those used in our 1988 report, to

1 The Canada Oil and Gas Lands Administration, Annual Report, 1989.

Table 6-2

Comparison of Estimates of Ultimate Recoverable Resource Potential for the WCSB

(EJ)

NEB - Control Case	250
NEB - Low sensitivity case	200
NEB - High sensitivity case	300
NEB - September 1988 Report	225
G. S. C. - 1983 Study - Average expectation	225
G. S. C. - 1983 Study - High confidence	190
G. S. C. - 1983 Study - Speculative estimate	320
Sproule Study (a)	250
WGML (b)	320
Consultees views	190 - 350
Sproule Study (Alberta only) (c)	215 - 255
NOVA Study (Alberta only) (d)	200
Alberta ERCB (Alberta only) (e)	185

(a) Submitted to NEB's GH-5-89 hearing (January1990).

(b) 1987 study.

(c) Submitted to the Alberta ERCB, January 1991

(d) Submitted to the Alberta ERCB, December 1990.

(e) AERCB Report ST91-18. Estimates now under review.

published estimates by the GSC and the ERCB and to the range of views provided during our consultations.

While we consider the range of estimates we are using in this report to be reasonable, albeit perhaps somewhat conservative in comparison with expressed views, we recognize that it does not address the full range of views provided to us during the consultations. However, in our view the range we have chosen is sufficient to provide insight regarding the impact of alternative assumptions regarding the size of the conventional natural gas resource in the WCSB and most estimates which are currently publicly available would fall within this range. To the extent that the results of studies underway by the GSC and ERCB, and others which may become available, provide different views in this regard it will be necessary for us in future reports to reconsider the reasonableness of our estimates.

The input received during our consultation process suggests that there is a view among some industry representatives that the upper end of our range of estimates is more reasonable. For example, natural gas transmission companies and smaller producers generally tended to favour the upper end of the range, or perhaps in some cases estimates in excess of this range. On the other hand, most of the larger producers tended to favour an estimate of ultimate potential for the WCSB between 200 and 250 EJ. Our statistical analysis suggests an ultimate recoverable resource potential for conventional natural gas resources in the WCSB consistent with the low end of our range, which would also be generally consistent with the GSC's 1983 high probability estimate. We consider this to be a conservative assessment of the resource potential, to which can be attached a very high probability. Parties consulted generally shared this view.

6.2.1.4 Unconventional Resources

The unconventional natural gas resources included in our study are those contained in very low permeability, or "tight", reservoirs and those which are potentially recoverable from coal. Both require unconventional exploitation techniques and to date there has been relatively limited investigation of these resources in Canada. Information upon which to base a projection of supply from these sources is therefore difficult to obtain, in part because producers wish to protect any competitive advantage they may have in terms of exploiting these resources.

The Canadian tight gas resource is primarily contained in reservoirs in west-central Alberta and north-eastern B.C. Estimates of gas-in-place for this area, which is often referred to as the Deep Basin, range up to 400 EJ. Estimates of this magnitude should be considered speculative at this point in time due to a lack of supporting technical data. Recovery of this gas will require the application of specialized production techniques, such as massive hydraulic fracturing, which would enable the gas to flow to the producing wells. The technical and economic viability of this resource has not yet been fully demonstrated and we have therefore included only a small portion of this resource in our supply projections (refer to section 6.2.2.2). Tight gas in Canada is generally considered to be gas produced from formations having a permeability less than 0.1 md. Although the technical definition used in the U.S. is very similar, gas from low deliverability uneconomic wells or from wells requiring massive hydraulic fracturing is defined as tight gas in the U.S. for the purpose of eligibility for tax credits. As a result, the tight gas classification tends to be applied more broadly in the U.S. and some gas classified as conventional in Canada would be classified as tight in the U.S.

Coalbed methane is natural gas, comprised almost entirely of methane, which is contained in coal formations. Given Western Canada's abundant coal resources, it has been speculated that coalbed methane may represent a significant future source of natural gas supply. However, coalbed methane research, exploration and development programs are at their very early stages in Canada. NOVA conducted some experimental work in the late 1970s and early 1980s and a number of other companies, largely prompted by the increasing interest in the exploitation of coalbed methane resources in the U.S., have recently begun to assess the technical and economic viability of natural gas production from coal seams in the WCSB.

Estimates of coalbed methane resources are not well-developed at this time. Only very approximate estimates have been made by applying estimates of average gas content to estimated resources of various grades of coal in Alberta and British Columbia. The Alberta Research Council has estimated the in-place coalbed methane resource in Alberta to be in the order of 2700 EJ (2600 Tcf). The B.C. Ministry of Energy, Mines and Petroleum Resources has estimated the in-place coalbed methane resource in that province

at 250 EJ (235 Tcf). There are also extensive coal deposits in Eastern Canada, the natural gas content of which has not been assessed at this time.

The estimates provided above are very preliminary and further study is underway to clarify the size, location and other characteristics of this resource in Canada, along with the economics associated with its extraction. In our view it is premature to explicitly consider coalbed methane in our natural gas supply projections, as any estimate based on the information available at this time would be extremely speculative. However, even if only a small fraction of the estimated in-place resource is economically recoverable, coalbed methane could prove to be a significant supply source in Canada in the not-too-distant future. We also anticipate that Canadian producers will benefit from the technology and experience currently being developed through the exploitation of this resource in the U.S. and that this could facilitate the exploitation of coalbed methane in Canada.

6.2.1.5 Summary

Canada's natural gas resource base is geologically and geographically diverse, and the individual characteristics of specific components will influence their future contribution to supply.

While there has been rather extensive exploitation of the conventional natural gas resources in the WCSB to date, our review and consultations with interested parties suggests that there remains substantial scope for future exploratory discoveries. We have used an estimate of 250 EJ for the ultimate recoverable resource potential for conventional natural gas in the WCSB in our Control Case, which would indicate that approximately 60 percent of this resource has been discovered and 28 percent produced to date. However, we recognize the diversity of views and uncertainty related to this estimate and therefore have used a range of estimates, from 200 EJ to 300 EJ in developing our supply projections. These uncertainties relate largely to the impact of future technological change and improved geological knowledge regarding the estimation of the size of the resource. While we consider the range of estimates being used in this report to be reasonable, we realize that it does not reflect the full range of views which were provided during the consultation process.

Canada has abundant natural gas resources in the frontier regions and these regions provide the potential for the development of discovered resources and for significant future exploratory discoveries. Approximately 55 percent of Canada's ultimate recoverable natural gas resource potential is estimated to be in the frontier regions. However, these resources are for the most part not readily accessible and their contribution to future supply will depend to a large extent on technological improvements to reduce capital and operating costs in the harsh environments of these regions and on future prices. Large investments will generally be required to develop these resources and to construct the transportation infrastructure necessary to deliver them to markets.

Canada is believed to have very large in-place resources of tight gas and coalbed methane. These resources are at an early stage of their exploitation and there is very limited information available on which to base an informed estimate of the extent to which these in-place resources may be technically and economically recoverable. We have therefore included only a modest provision for tight gas and have not explicitly accounted for coalbed methane in our analysis. To the extent that these supply sources become viable over our projection period, our assessment of unconventional recoverable natural gas resources may well be understated.

6.2.2 Canadian Supply Costs

In the preceding section, we described the ultimate recoverable natural gas resource potential. Only part of this potential is currently recognized as reserves. This is the case either because the resource has been discovered but is not currently considered to be economically viable ("Other Discovered Recoverable Conventional Resources") or because it has not yet been discovered ("Undiscovered Recoverable Conventional Resources"). Over the projection period, a portion of the resources included in both these categories will be added to reserves and can be expected to contribute to natural gas supply. The extent to which these reserves additions can be anticipated to occur is determined by the characteristics of the resource and by economic factors. The pace at which exploration proceeds, or the time at which a specific development proceeds, is largely dependent upon the perceived profitability of these activities.

To motivate producers and resource owners to bring on new natural gas supplies, we assume in our analysis that producers will perceive that over the long-term the price which is received will have to cover the total cost of

bringing on these supplies. This total cost is referred to as the incremental supply cost. In this section we describe the methodology used to develop our projections of supply costs for conventional and unconventional gas in the WCSB and for conventional gas in the frontier regions, as well as the results of our analysis. The resultant supply costs are used in developing our projections of supply from reserves additions, as discussed in section 6.4.6.

Incremental supply costs are the sum of direct costs and user costs. Direct costs include the capital costs associated with resource exploration, where appropriate (i.e. for undiscovered resources), the capital costs for development and the capital and operating costs associated with resource production. The supply cost also includes provision for a return to the producer, in that the capital cost includes a rate of return on equity and an interest rate on debt. The cost of gas also includes a return to the resource owner. In this analysis we have used user cost as a proxy for royalties, as explained in section 6.1. The user cost calculation is another way of projecting a long-term estimate of what resource owners could collect as royalties. However, it is not necessarily the case that royalties are determined in this manner.

In order to estimate supply costs which will provide a reasonable return on investments from an industry perspective, we use a discount rate that reflects the corporate pre-tax cost of capital. We have used a ten percent real before tax cost of capital in all of our supply cost calculations, which should provide on average an eight percent real after tax rate of return on equity. A more extensive discussion of our approach to the discount rate calculation and to the use of supply cost estimates to estimate start-up dates for projects is provided in section 7.2.1.2.

In the remainder of this section, and in section 6.2.4 which discusses the U.S. supply costs used in our natural gas market analysis, we will focus on the direct costs which are the inputs to the analysis. However, the user costs are fully reflected in the supply, demand and price projections arising from our analytical results.

6.2.2.1 Conventional Resources of the WCSB

To estimate the direct costs of undiscovered recoverable resources in the WCSB, we estimate the costs of increments of reserves additions and thereby develop a direct cost curve.[1] The direct cost curve is derived by first estimating the determinants of direct costs as a function of cumulative reserves additions and then using these projections to estimate direct costs as a function of cumulative reserves additions.

A major determinant of the direct costs for undiscovered recoverable resources is the reserves added per metre of exploratory drilling. Other important determinants are the input costs, such as the cost of exploratory and development drilling per metre, associated with the exploration, development and production of the resource.

With regard to the reserves added per metre of exploratory drilling, we assume a progressive decline in the rate, as shown in Figure 6-5, such that the finding rate becomes very modest as the ultimate resource potential is approached. As a result of the use of this declining rate, direct costs per unit of reserves additions progressively increase as a function of cumulative additions. A step change in the historical reserves additions rate trend is evident following the discovery of larger pools early in the exploitation of the WCSB. This, and the variability in the historical data since that time, is indicative of the difficulty in establishing a definitive trend line. There is considerable uncertainty as to how the size and characteristics of the undiscovered recoverable resource and technological change might influence this trend in the future. While we believe it to be reasonable to project a progressive decline in the reserves additions rate trend as the basin becomes more depleted, we are of the view that it is important to reflect a range of outlooks in our projections. For this reason we have conducted sensitivity tests to examine the impact of different trends on direct costs and on our analytical results. We have based these sensitivity cases on higher and lower estimates of ultimate resource potential, as depicted in Figure 6-5. However, we wish to emphasize that there are a number of other factors which influence the reserves additions rate trend and could also cause the trend to deviate from that which we have used in the Control Case. A higher estimate of ultimate recoverable resource potential results in a more gradual decline in the reserves additions rate and thereby in lower direct costs. A lower estimate of resource potential has the opposite effect using our methodology.

1 A more detailed description of this methodology is found in the paper "Trends in Crude Oil and Natural Gas Reserves Additions Rates and Marginal Supply Costs for Western Canada " by B. Bowers and R. Kutney published in the Canadian Journal of Petroleum Technology, Volume 28, 1989.

Figure 6-5
Natural Gas Reserves Additions Rate Trend for WCSB

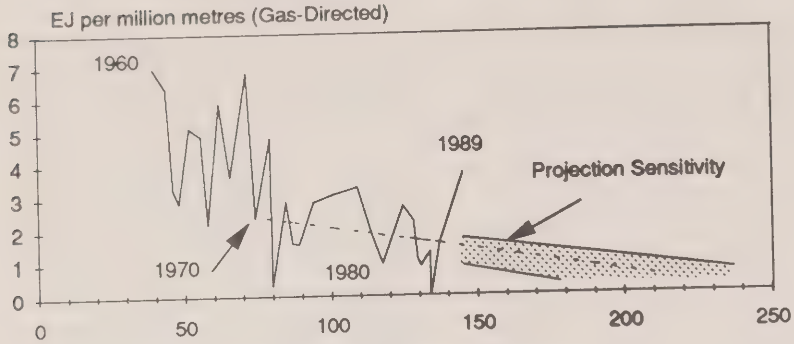


Table 6-3
Input Costs for Natural Gas Reserves Additions in the WCSB

(Control Case)

Exploratory Drilling ($C 1990 /m)	350.00
Development Drilling ($C 1990 /m)	265.00
Field Equipment ($C 1990 1000/well)	260.00
Gas Plants ($C 1990/GJ of additions)	0.12
Fixed Costs per year ($C 1990 1000/well)	34.00
Variable Cost ($C 1990 /GJ)	0.20

Note: Geological and geophysical costs are assumed to be 30 percent of exploration and development drilling costs in both cases.

We have relied on CPA statistical data for the estimation of the input costs associated with the exploration, development and production of future reserves additions. The input costs used for our calculations are given in Table 6-3. These are long term averages of the historical data. The historical annual data for the cost per metre of gas-directed exploration and development drilling in the WCSB is provided in Figure 6-6. The input drilling costs have a significant impact on the direct cost estimates and the assumptions made in this regard are therefore quite important. For the purposes of this analysis we have used drilling costs per metre which tend to be toward the lower end of the historical range and which to a large degree reduce the influence of costs experienced during the late 1970s and early 1980s. We have made this assumption regarding drilling costs because we believe that the costs experienced during a period of very high drilling activity in the late 1970s and early 1980s were somewhat exceptional and because we believe that technological advances will continue to have a dampening effect on cost levels. In addition, some observers have suggested that the changing structure of the industry, with more activity being conducted by small and intermediate producers will tend to reduce costs over the longer term. We do recognize, however, that when gas-directed activity again increases there will be upward pressure on costs for at least a period of time as the drilling and service sector adjusts. On the other hand, significant technological progress could have the effect of further reducing costs relative to the levels we have selected. While our methodology produces rather smooth trends in the progression of future costs, we recognize that in reality costs will fluctuate with changes in activity

Figure 6-6

Historical Drilling Cost Per Metre in the WCSB

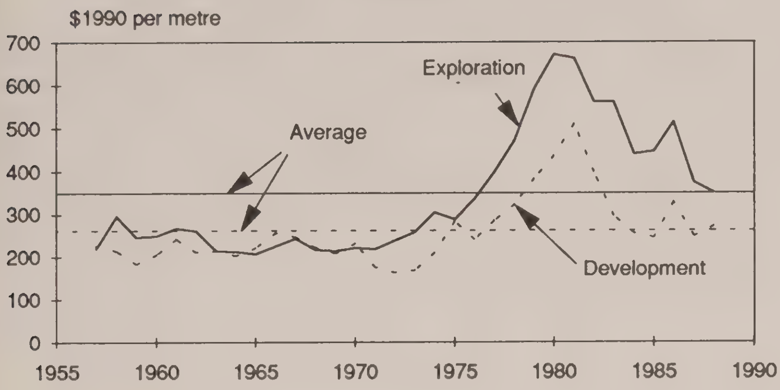
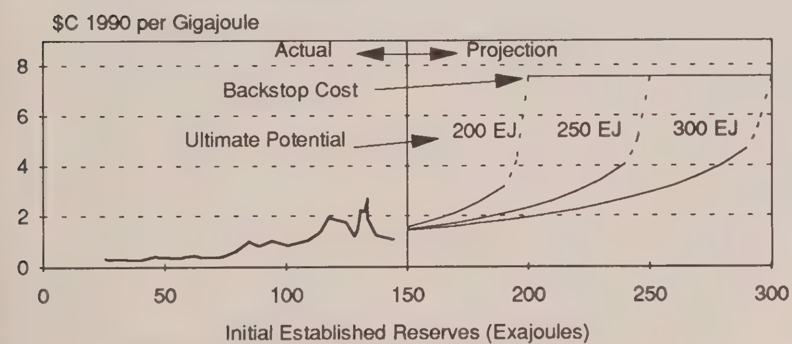


Figure 6-7

Net Incremental Direct Costs for Control Case and Resource Sensitivity Tests (Including Rate of Return to Producer)



Note: Costs reflect connection schedule 2 of Table A6-11.

levels and the introduction of technological innovation. We do not attempt to project periodic fluctuations in cost trends.

Another factor affecting the supply costs is the allocation of by-products of natural gas processing. Field gas plants produce natural gas liquids and sulphur. Revenues received for these products partially offset the costs of natural gas production and we therefore include them as a credit in the estimation of net incremental direct costs. To calculate this credit, we assume that future prices for natural gas liquids will maintain their historical relationship with the price of crude oil, and that prices for sulphur will remain constant at approximately $C(1990) 90 per tonne, reflecting the current value.

Figures 6-7 and 6-8 show the net incremental direct costs for conventional natural gas in the WCSB for the Control Case and the resource sensitivity tests with and without a before tax rate of return to the producer, respectively (refer also to Appendix Table A6-2). The increase in the direct cost with cumulative additions is due to the decline in the reserves additions rate trend. These figures illustrate the sensitivity of the results to alternative views regarding future trends in this parameter.

As previously noted, our direct costs include exploration, development and production costs. A breakdown of the components of the Control Case direct cost curve is shown in Figure 6-9. We show the costs calculated without a before tax rate of return to the producer in order to facilitate comparison to other published cost estimates.

Our net incremental direct cost projection for the Control Case is lower than both the high and low cases from the 1988 Report (Figure 6-10), due to our use of a somewhat higher estimate of ultimate recoverable resource potential and lower unit cost inputs in the Control Case.

Figure 6-11 provides a provincial breakdown of our projection of net incremental direct costs for the Control Case which were used as input to he NARG. We have developed these projections using provincial reserves additions rate trends and input costs. They are intended to be illustrative of the range of costs applicable on a regional basis for the WCSB and conform to the provincial estimates of ultimate recoverable resource potential described earlier.

6.2.2.2 Unconventional Resources of the WCSB

There is very limited information available concerning the direct costs associated with the exploration, development and production of unconventional natural gas resources of the WCSB.

We have used information provided by Canadian Hunter to estimate direct costs for very low permeability reservoirs in the Deep Basin region of Alberta and northeastern B.C.

As noted in section 6.2.1.4, we have not estimated direct costs for coalbed methane resources in Western Canada because of a lack of information. Any estimate we would develop based on the information available at this time would be extremely speculative.

Figure 6-8

Net Incremental Direct Costs for Control Case and Resource Sensitivity Tests (Excluding Rate of Return to Producer)

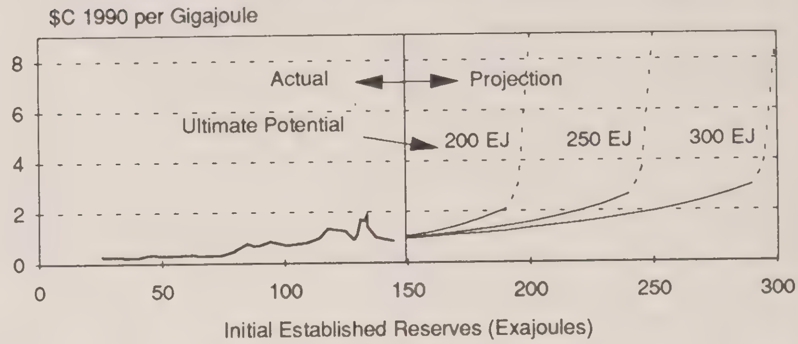


Figure 6-9

Components of the Control Case Direct Costs (Excluding Rate of Return to Producer)

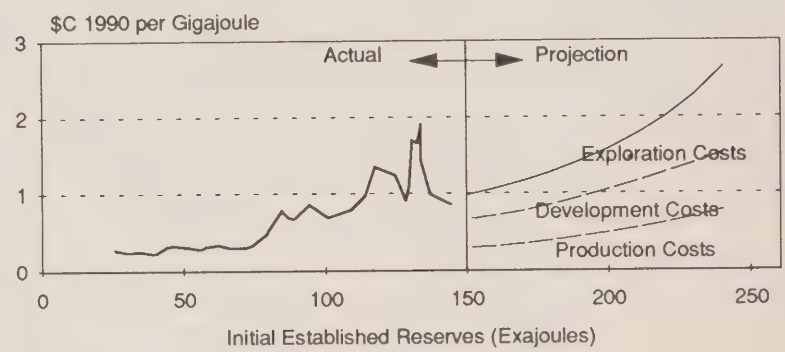


Figure 6-10

Comparison of Control Case Direct Costs to 1988 Report (Excluding Rate of Return to Producers)

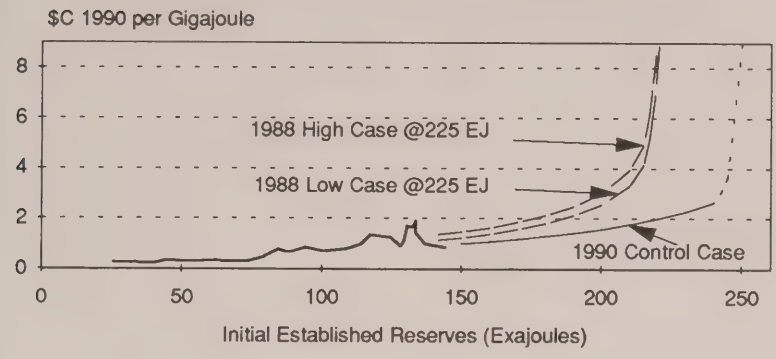
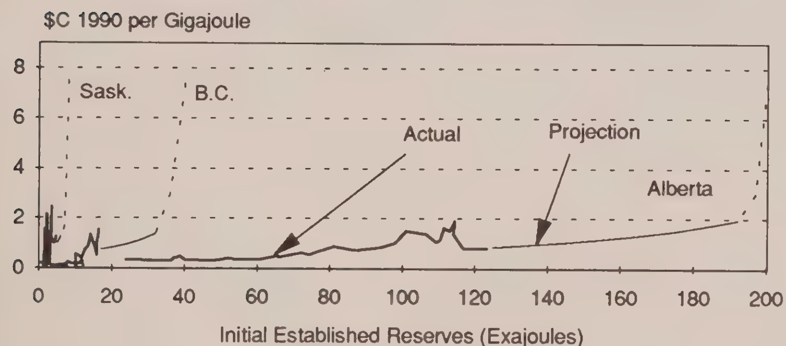


Figure 6-11

Provincial Breakdown of Control Case Direct Costs (Excluding Rate of Return to Producers)



6.2.2.3 Frontier Resources

The methodology used to determine direct costs for resources in the Mackenzie Delta/Beaufort Sea region and in the East Coast Offshore region is very similar to that used for the WCSB, although our frontier cost estimates rely more heavily on cost data that is available for specific major projects. The direct cost estimates for discovered resources include the capital costs associated with development and the capital and operating costs associated with resource production. The direct cost estimates for undiscovered resources include capital costs for exploration in addition to the costs noted above.

The direct costs for the established reserves recognized by the Board in the Mackenzie Delta region are based largely on evidence submitted by the project sponsors (Esso, Gulf and Shell) in their recent natural gas export licence application.[1] The estimated direct cost at the plant gate, including the before tax return to the producer, for the established reserves of approximately 9 EJ is in the order of $1.10 GJ in 1990 Canadian dollars.

In estimating the direct costs for undiscovered resources in the Mackenzie Delta/Beaufort Sea region, we relied on information from a recent Board hearing[1] and on estimates of undiscovered resource potential provided by the Geological Survey of Canada. Average exploration costs in this region were estimated by the applicants to be $60 million for a discovery in the onshore/shallow offshore areas. We increased this to $90 million for discoveries in the deeper offshore areas, reflecting

1 National Energy Board, *Reasons for Decision, GH-10-88,* August 1989.

the higher costs of drilling in deeper water. The recoverable volumes associated with these expenditures were not specified and we have therefore used these average costs for all discoveries projected by GSC in the region. We further assumed that development and production costs would be equivalent to those for pools of a similar size to those included in the applications. Development and production costs for pool sizes not included in the applications, and for which the GSC identified undiscovered resource potential, were obtained by interpolation.

The total direct costs for each pool size are the sum of the capital and operating costs associated with exploration, development and production. To establish a likely range of costs, we determined that pools smaller than 37 PJ (35 Bcf) in the onshore areas and 105 PJ (100 Bcf) in the offshore areas would be uneconomic to develop on a half cycle basis (i.e.. including development and production costs but excluding exploration costs). For a lower limit on future direct costs on a unit basis, we accepted the GSC's view that the maximum size of new discoveries would likely be less than 1 EJ in both the onshore/shallow offshore and the deeper offshore regions of the Delta. The results of this analysis suggest that approximately 30 EJ of natural gas would be available from the Mackenzie Delta/Beaufort Sea region at plant gate direct costs, including a before tax return to the producer, less than $3.10/GJ. This is comprised of the 9 EJ of established reserves and approximately 21 EJ of undiscovered recoverable resources. Transportation costs to deliver this gas to markets must be added to the plant gate costs, resulting in a substantially higher delivered cost. Further recoverable resource potential would be anticipated at costs in excess of this level, but we have not attempted to quantify the relationship between volumes and costs for these additional resources because the costs are uncertain and they would not be expected to contribute to supply over the projection period.

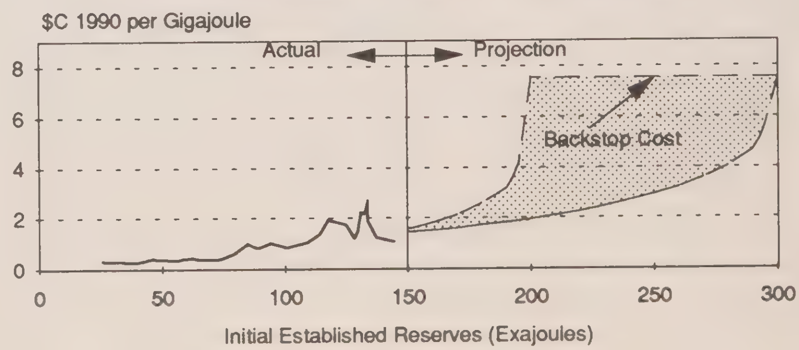
Direct cost estimates for natural gas from the East Coast Offshore region are to a large extent based on the original Sable Island development plan. We adjusted these costs to account for possible joint development of discovered resources by Mobil and Shell. We estimate that about 2 EJ would be available from this region at a plant gate direct cost, including a before tax return to the producer, less than $3.00/GJ and 5 EJ at a cost less than $4.50/GJ. These direct costs are at the plant gate of an onshore processing facility. Other known accumulations are smaller than the Venture discovery and would be expected to have higher direct costs on a unit basis.

The direct cost estimates used in our analysis, while for the most part based on recent published information and industry input, remain uncertain. There is a considerable lead time prior to the anticipated start-up dates for these projects and it is possible that significant technological change could occur over this period which would have the effect of reducing the capital and operating costs relative to these costs. Recent advances in offshore production practices would tend to support this view.

We have not attempted to estimate direct costs for other frontier resources because they are very speculative and because we do not anticipate that they will contribute to natural gas supply during the time frame of our projection.

Figure 6-12

Range of Direct Costs For Canadian Natural Gas (Including Rate of Return to Producer)



6.2.2.4 Summary

Figure 6-12 illustrates the range of direct costs for Canadian natural gas which we have used in our gas market analysis. It is important to recognize that there is a gradation in costs, progressively increasing through various supply sources until ultimately the backstop level of costs is reached (for further detail regarding backstop costs refer to section 6.2.4).

We have provided a range of direct cost estimates for conventional natural gas from the WCSB and have observed that there is considerable uncertainty related to cost estimates of this nature. The uncertainties relate to estimates of ultimate recoverable resource potential, projections of reserves additions rate trends, the impacts of activity levels and technological change on costs and other input parameters and perhaps to some degree the changing structure of the industry. As was the case for estimates of ultimate recoverable resource potential, we consider the range of direct costs estimates we are using to be a reasonable one which takes account of variances which could arise due to combinations of the above factors. However, we recognize that it does not take into account the full range of views provided during our consultations. Fundamentally, we are attempting to project costs which reflect both the progressive depletion of the resource, which creates upward pressure on costs, and technological change, which tends to reduce costs. We have attempted to reflect a measure of technological improvement in our cost projections. However, to quantify the impact of technological change on costs is difficult and we recognize that some will suggest that we have not yet adequately accounted for the extent to which improvements in technology mitigate increases in costs as a function of cumulative reserves additions. In the extreme, some would go so far as to argue that supply cost curves are essentially flat in real terms over a long period of time.

We have included direct cost estimates for the tight gas component of the unconventional natural gas resource in Western Canada in our projections but have not included cost estimates for coalbed methane because the available information is very limited and such estimates would therefore be extremely speculative. However, based on recent experience in the U.S., it may well be possible that some coalbed methane resources will be competitive with other Canadian supply sources over the projection period. To the extent that this is the case, our natural gas supply projections may be understated.

Our direct cost estimates for the frontier regions are based to a large extent on information which is available regarding specific projects. Given the long lead times prior to the anticipated startup dates for these projects, it is quite possible that technological advances will have the effect of reducing costs from those which we have used in this analysis.

6.2.3 U.S. Resources

Although we have made some relatively minor adjustments to estimates of U.S. resources on the basis of our consultations, for the most part we have relied on information available in the public domain, particularly that which is provided by the U.S. Energy Information Administration (EIA) and the Potential Gas Committee (PGC). The terminology used in the U.S. for classification of resources differs in some respects from that which we have used for Canada. We have not attempted to modify the terminology to make it more consistent, but rather have retained the terminology used by those who have developed the estimates and provide definitions in the text and glossary for clarification, where necessary. The classification terminology used by the Potential Gas Committee is described in the inset box.

Future U.S. production of natural gas will be obtained from remaining proved reserves and from potential natural gas resources. For the former we have relied on estimates provided by the EIA, and for the latter primarily on estimates provided by PGC (Table 6-4).

6.2.3.1 U.S. Reserves

The estimates of U.S. natural gas reserves presented in Table 6-4 are those of the Energy Information Administration (EIA) at year-end, 1988.[1] This is the only comprehensive publicly available estimate of U.S. natural gas reserves.

The estimates are of proved reserves, which EIA defines as "those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainly to be recoverable in future years from known reservoirs under existing economic and operating conditions."

The EIA's estimate of proved gas reserves for the Lower 48 States at year-end 1988 is 158 Tcf. Approximately 40 percent of the reserves are located in the

1 *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 1988 Annual Report.*

PGC Estimation Categories

The classification terminology used by the PGC for its estimates of U.S. natural gas resources is described below.

<table>
<tr><td colspan="5">Ultimately Recoverable Resources</td></tr>
<tr><td colspan="2">Discovered Recoverable Resources</td><td colspan="3">Undiscovered Recoverable Resources</td></tr>
<tr><td rowspan="2">Cumulative Production</td><td rowspan="2">Proved Reserves</td><td colspan="3">Potential Gas Resources</td></tr>
<tr><td>Probable*</td><td>Possible**</td><td>Speculative***</td></tr>
</table>

Decreasing Availability of Geological and Engineering Data -------->

*Probable Resources are associated with known fields and are the most assured of potential supplies. A relatively large amount of geologic and engineering information is available to aid in the estimation of the resource existing in this category. Probable resources bridge the boundary between discovered and undiscovered resources. These consist of both extensions to existing pools and new pool discoveries within existing fields.

**Possible Resources are a less assured supply because they are postulated to exist outside of known fields, but they are associated with a productive formation in a productive province. Their occurence is indicated by a projection of plays or trends of a producing formation into a less well-explored area of the same geologic province or subprovince.

***Speculative Resources are the most nebulous category, as they are expected to be found in formations or provinces that have not yet proven to be productive. Geological analogs are developed in order to ensure reasonable evaluation of these unknown quantities.

Table 6-4

United States Control Case Natural Gas Resource Estimates

TCF [a]

Supply Region	Proved Reserves [b]	Potential Natural Gas Resources [c]			
		Probable	Possible	Speculative	Total
Offshore Gulf	33	27	55	29	111
Rocky Mountains	14	39	51	17	107
Anadarko Basin	33	29	27	30	86
Onshore Gulf	35	26	39	20	85
Appalachia	7	22	8	27	57
West Texas	14	14	33	1	48
Pacific	5	2	14	9	25
Midwest	1	2	7	8	17
Atlantic	0	0	0	13	13
Great Plains	1	3	3	4	10
San Juan Basin	15	2	1	0	3
Subtotal Lower 48 States	**158**	**164**	**237**	**159**	**562**
Alaska	9	9	29	81	118
Total	**167**	**173**	**266**	**240**	**679**

[a] 1 TCF is approximately equal to 1.05 EJ.
[b] Energy Information Administration, year-end 1988.
[c] 1988 Potential Gas Committee "Most-Likely" Estimates adjusted to exclude coalbed methane (90 TCF) and certain remote and deep water areas (approximately 20 TCF).

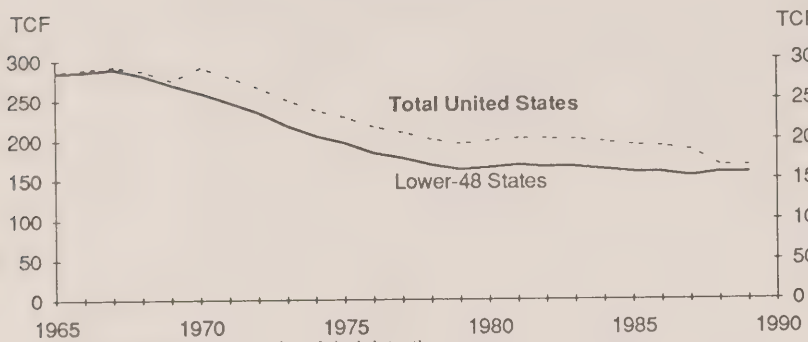
onshore producing areas of the Louisiana and Texas Gulf Coast and the offshore Gulf of Mexico. Other areas with significant proved gas reserves include New Mexico (17 Tcf), Oklahoma (16 Tcf), Wyoming (10 Tcf) and Kansas (10 Tcf). The EIA does not specifically identify coalbed methane reserves. The total reserves attributed to coalbed methane by GRI[1] were 0.6 Tcf at year-end 1988 and increased to 1.9 Tcf at the end of 1989.

Each year the proved reserves of natural gas are reduced by annual production, increased by discoveries and changed by the volumes of adjustments and revisions. Figure 6-13 shows the trend in remaining proved reserves in the U.S. over the past 25 years. Remaining proved reserves increased to a peak of approximately 290 Tcf in 1967 and have subsequently declined, as reserves additions have generally not kept pace with production. However, in recent years the U.S. industry has replaced a high proportion of its annual production. Many observers attribute this to cumulative technological advances in natural gas exploration and production techniques. A substantial portion of the estimated reserves additions have occurred through appreciation in conventional producing formations in existing fields. These reserves additions have occurred despite a significantly lower level of drilling activity from that attained in the early 1980s.

1 P.D. Holtberg, T.J. Woods, M.L. Linton and N.C. McCabe, *1991 Edition of the G.R.I. Baseline Projection of U.S. Energy Supply and Demand to 2010*, Gas Research Institute, Chicago, Illinois, 1990.

Figure 6-13

United States Proved Remaining Natural Gas Reserves



Source:Energy Information Administration

In its estimate of proved reserves the EIA previously included 33 Tcf for Alaska. However, in 1988 the EIA removed 24.6 Tcf of these volumes from the proved reserves category because they did not satisfy the criteria that they must be recoverable under *existing* economic and operating conditions. We have included the volumes removed from proved reserves in our estimates of potential natural gas resources.

6.2.3.2 U.S. Potential Natural Gas Resources

In our 1988 Report, we used the 1986 Potential Gas Committee estimates for potential natural gas resources. For this report, we considered various estimates of resources available in the public domain and consulted with industry and government in the U.S.

The principal estimates of resources for the U.S. available in the public domain are those prepared by the United States Department of the Interior (Geological Survey and Mineral Management Service) (DOI), the Potential Gas Committee (PGC) and the United States Department of Energy (DOE). There is wide diversity among the respective published estimates of U.S. natural gas resources, ranging from 399 Tcf for DOI to 1188 Tcf for DOE.[1] Although the published estimates differ considerably, it is apparent, as shown in Table 6-5, that this can be largely attributed to differences in the types of resources which were considered in the estimates. For example, DOI did not consider any unconventional resources in its estimate and DOE postulated that substantial additional resources would be obtained from appreciation of proved reserves. Once the estimates are appropriately disaggregated, it is evident that the elements they hold in common carry quite similar resource estimates. The assessments differ primarily with respect to the extent to which appreciation of proved reserves and "unconventional" resources are included in the estimates.

Following our consultations, we decided to use the 1988 PGC "most likely" estimate of potential natural gas resources as the basis for our Control Case projection. While we recognize the uncertainty associated with such estimates, we concluded that the PGC most likely case was a reasonable "middle-of-the road" estimate which was widely recognized and accepted.

The PGC estimates are of natural gas which can be recovered by conventional means given adequate economic incentives in terms of price/cost relationships and generally utilizing current technology.

The PGC's estimates do not include proved natural gas reserves in discovered fields. Estimates of potential natural gas resources are categorized as probable, possible and speculative resources. These resource categories are an expression of the quantity and quality of geological and engineering data upon which the estimates are based. For each of the three resource categories, a maximum, most likely and minimum estimate is provided.

For the Control Case projection we have used the sum of the probable, possible and speculative estimates for the PGC's most likely case. The most likely estimates

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1 In our analysis we used the most recently available published estimates at the time the analytical work was being conducted. The PGC is currently completing an update of its 1988 report on its usual biennial cycle. The DOE has recently issued an update of its previous estimate as part of the National Energy Strategy review.

Table 6-5

Comparison of Estimates of United States Natural Gas Resources

[Tcf]

	DOI [a]	PGC [b]	DOE [c]
Published Estimate	399	796	1188
Less :			
Proved Reserves			168
Probable / Inferred Resources		173	111
Associated Reserves			61
Extended Reserves			119
Shale Gas			31
Coalbed Methane		90	48
Tight Gas		107 [d]	180
Alaska	75	118	129
Undiscovered "Conventional" Gas in the Lower-48 States	**324**	**308**	**341**

[a]Estimates of Undiscovered Conventional Oil and Gas Resources in the United States: United States Department of the Interior, 1989.
[b] Potential Supply of Natural Gas in the United States :Potential Gas Committee, 1988.
[c] An Assessment of the Natural Gas Resource Base of the United States: United States Department of Energy, 1988.
[d] DOI working papers estimate that 107 TCF of "tight" gas is recoverable with current technology. Accordingly we have used this estimate to approximate the removal of "tight " gas resources from the PGC estimates.

Table 6-6

U.S. Lower-48 States Ultimate Natural Gas Resource Potential as of Year-end 1988 [a]

TCF

	Control Case	High Resource Sensitivity Case
Cumulative Production	697	697
Proved Reserves	158	158
Potential Resources	560	846
Total	**1415**	**1701**

[a] Potential Estimates are for the Lower-48 States adjusted to exclude coalbed methane and certain deep water and remote areas.

represent neither the maximum potential that could be recovered if conditions were more favorable than currently envisioned, nor the minimum potential which could be postulated to exist under the most conservative interpretation.

The estimates of potential gas resources used in our Control Case projection are provided in Table 6-4. We have adjusted the PGC estimates to exclude coalbed methane (90 Tcf), which we account for in our supply projections as described in section 6.2.4, and resources in certain remote and deep water areas, primarily in the Gulf Coast Offshore (approximately 30 Tcf). The resultant potential natural gas resource for the Lower 48 States is 560 Tcf. Almost 400 Tcf is contained in four producing regions: Offshore Gulf of Mexico (111 Tcf), Rocky Mountains (107 Tcf), Anadarko Basin (86 Tcf) and the Onshore Gulf, primarily Louisiana and Texas (84 Tcf). A further 118 Tcf is estimated for Alaska, primarily on the North Slope. Of the total estimate of potential gas resources including Alaska, 25 percent is in the probable category, 40 percent in the possible category and 35 percent in the speculative category. This distribution is similar for the Lower-48 States.

Given cumulative production of 697 Tcf, proved reserves of 158 Tcf and potential natural gas resources of 560 Tcf, the ultimate recoverable resource potential for the U.S. Lower 48 States for the Control Case is estimated at 1415 Tcf (Table 6-6).

The PGC resource estimates included coalbed methane for the first time in 1988. The estimate for the most likely case was some 90 Tcf of recoverable natural gas. As noted above, we have excluded

coalbed methane from Table 6-4 because we have not used this estimate directly in developing our supply projections. Instead, we have relied on analysis by the Gas Research Institute (GRI) as the basis for our projection of the supply of coalbed methane over the projection period. Therefore, some coalbed methane is included in our analysis, although the amount is not explicitly stated in Table 6-4.

The natural gas resource potential from tight (low permeability) formations, including sandstone, shale and carbonate reservoirs, is included in the PGC estimates, but only to the extent that these resources are viable under the economic and technology assumptions used by the estimators. However, it is not possible to specifically identify the volume of tight gas included in the PGC resource estimates. (In our comparative analysis of various U.S. resource estimates we have used an estimate of 107 Tcf based on a DOI estimate).

The potential resource from Devonian shale is largely excluded from the PGC estimates, with the exception of that which the Committee believes to be recoverable by normal drilling, well stimulation and completion techniques and which is analogous in geological setting to previous production.

Finally, and as noted earlier, the PGC natural gas resource estimates, like those for Canada, are subject to considerable uncertainty. In the high resource sensitivity case, we used 846 Tcf, which is just less than 80 percent of the PGC maximum resource estimate of 1085 Tcf, to represent the undiscovered U.S. natural gas resource potential. This results in an estimated ultimate potential of 1700 Tcf for the Lower-48 States in the high U.S. resource sensitivity case (Table 6-6).

A comparison of the Canadian and U.S. resource estimates used in our analysis is provided in Table 6-7.

As described in section 6.5, we have tested the sensitivity of our Control Case projections to alternative views regarding the size and regional distribution of the U.S. natural gas potential.

The PGC most likely case resource estimates used in our Control Case analysis, disaggregated by NARG region, are provided in Appendix Table A6-3.

6.2.4 U.S. Supply Costs

In this section we discuss the supply cost estimates we have used for U.S. resources, first for conventional and unconventional gas in the Lower 48 States and then for Alaskan gas. As for Canada, the costs discussed in this section are direct costs and therefore do not include the user cost. (The user cost is incorporated in price formation as described in section 6.1.) This section concludes with a discussion of other supply - related input parameters used in the North American gas market analysis.

The costs of U.S. natural gas supply are a significant determinant of the overall level of natural gas prices in the North American market and also influence interregional gas flows. We have relied heavily on estimates of direct costs developed by Geological Exploration Associates (GEA) for

Table 6-7

Comparison of Control Case Estimates of Natural Gas Resources

EJ [a]

	Canada Year-end 1989 [b]		United States Year-end 1988 [c]	
	WCSB	Total	Lower-48	Total
Cumulative Production	71	71	697	700
Remaining Reserves	74	86	158	167
Other Discovered Recoverable Resources	0	29	n/a	n/a
Undiscovered Recoverable Resources	105	375	n/a	n/a
Potential Natural Gas Resources	n/a	n/a	560	678
Ultimate Recoverable Resource Potential	**250**	**561**	**1415**	**1545**

[a] 1EJ is approximately equal to 0.95 TCF
[b] Excludes coalbed methane and natural gas contained in low permeability reservoirs
[c] Excludes coalbed methane.

the PGC's 1986 estimate of undiscovered gas resources, as subsequently modified by Decision Focus Incorporated (DFI) and the California Energy Commission (CEC).[1] The net result of the adjustments made by DFI/CEC to the GEA cost estimates was to increase the cost of producing gas in various U.S. producing regions to levels more consistent with historical practice. We have further modified these cost estimates to reflect input received during our consultations, to make them consistent with the PGC's 1988 estimates of undiscovered resources and to reflect improvements in technology which we anticipate will occur over the projection period.

GEA estimated the full cycle costs of finding, developing and producing gas from most of the geological regions defined by the Potential Gas Committee. For each region, costs were developed for the estimates of undiscovered resources included in the PGC's 1986 report. The GEA cost estimates assume that 12 percent of exploration wells and 85 percent of development wells will be successful. For each geological play, an assessment was made of the reserves additions per successful gas well. Drilling costs were based on the Joint Association drilling cost surveys.[2] Estimates of the costs of field facilities and of production costs were based on information provided by the U.S. Department of Energy.[3] Plant processing costs were not included in the GEA cost estimates, in that it is assumed that in many instances the necessary infrastructure would already exist and that processing costs would be offset by byproduct revenues. GEA used cost data for the 1982 to 1986 period in deriving their estimates. The cost per foot of drilling and other input costs had generally declined over this period from the peak levels observed in the late 1970s.

We made several adjustments to the GEA and DFI/CEC direct cost estimates. First, we adjusted the direct cost curves by scaling them to conform to the PGC's 1988 estimates of resource potential. Second, for several producing regions the costs were adjusted to reflect the input which was provided by U.S. industry and government consultees. Third, although costs for the 1982 to 1986 period had declined somewhat from earlier levels, we were of the view that ongoing improvements in technology, such as better seismic and drilling techniques, would have the effect of further reducing input costs in real terms as compared to those observed over the 1982 to 1986 period. While the future rate of technological improvement is unknown, a rate of change of one percent per year would result in cost reductions of 25 to 30 percent in real terms when compounded over the projection period. We assumed that technological improvements would reduce direct capital costs at a rate of one percent per year until costs had been reduced by 25 percent and also reduced operating costs to 65 percent of the GEA/DFI/CEC estimates over the period.

Our Control Case direct cost estimates for certain of the more important supply regions in the U.S., with and without a before tax rate of return to the producer, are provided in Figures 6-14 and 6-15, respectively. Those including a rate of return to the producer are used in our analysis of gas prices and flows. For comparative purposes, these figures also show direct costs for conventional natural gas in Alberta. Although we have endeavoured to approach the estimation of U.S. and Canadian direct costs in as consistent a manner as possible, the underlying methodologies and basis for cost estimation differ and the comparisons therefore remain approximate in nature.

Appendix Table A6-4 provides more detail regarding the direct costs used in our Control Case analysis for the various U.S. supply regions. To the extent that tight gas is included in the PGC resource estimates, it is also reflected in these direct cost estimates.

As discussed in section 6.2.3, the U.S. has very large resources of coalbed methane and there has recently been a significant increase in coalbed production, particularly from the San Juan Basin. However, there is currently limited information publicly available regarding the direct costs associated with the exploitation of coalbed methane. The tax credit provided to producers in the U.S., which has recently been extended to 1992, further increases the difficulty in assessing the economic viability of this resource. For these reasons, we have not attempted to develop an independent estimate of direct costs for coalbed production. We have used costs for

1 *An Economic Evaluation of Alternative Interstate Pipeline Projects to serve California*, California Energy Commission, March, 1989.

2 American Petroleum Institute, Independent Petroleum Associations of America, Mid-Continent Oil and Gas Association "Survey on Drilling Costs".

3 Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations.

Figure 6-14

Direct Costs for Selected North American Supply Regions (including returns to producers)

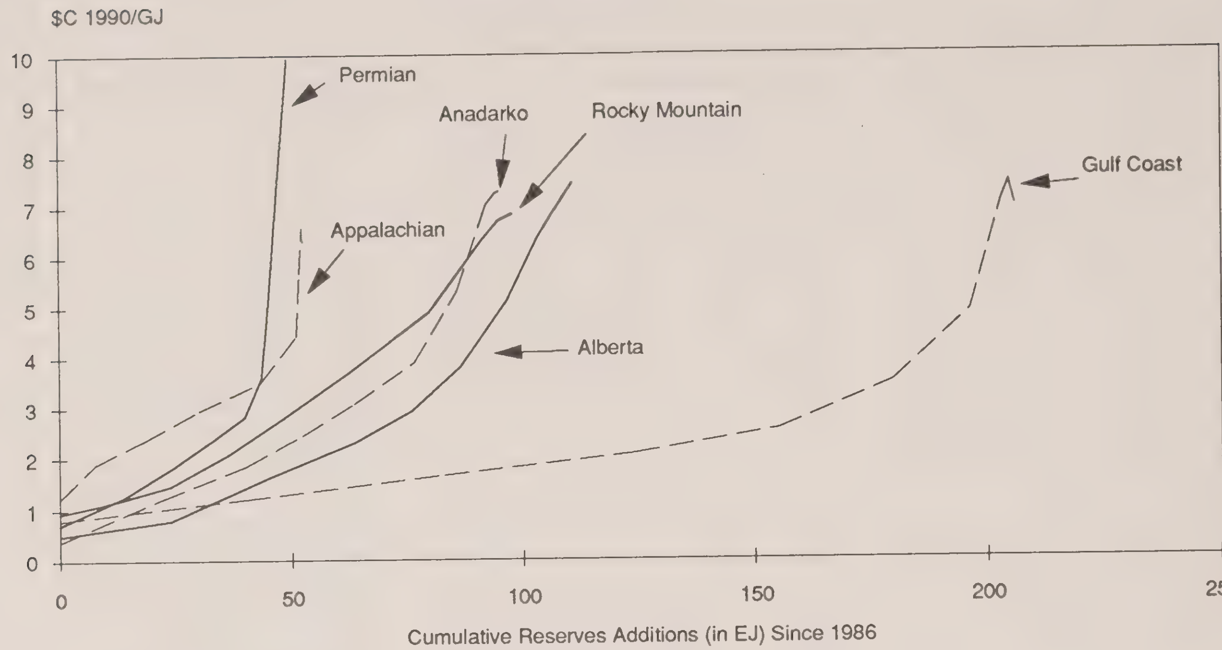
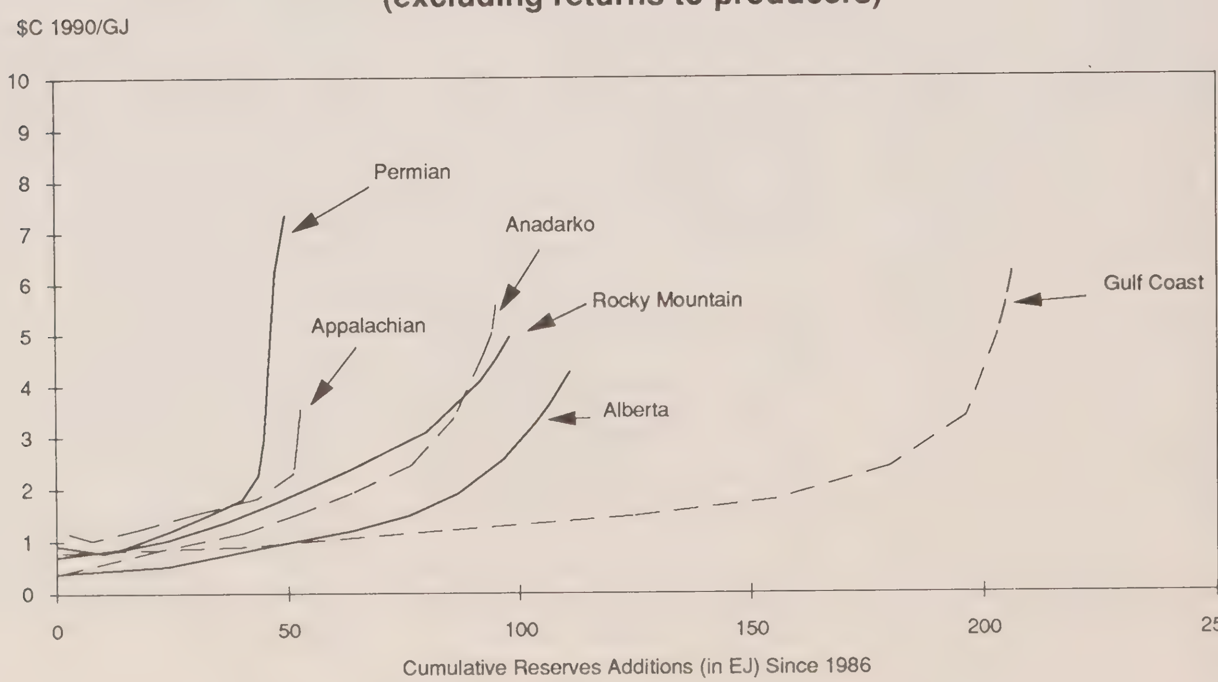


Figure 6-15

Direct Costs for Selected North American Supply Regions (excluding returns to producers)



coalbed methane from the San Juan, Black Warrior and Appalachian regions which, given our price projection, have the effect that our projections of coalbed methane production approximately match the Gas Research Institute's 1991 Baseline projection[1] of coalbed production from these regions over the projection period.

For Alaskan gas, we have relied on direct cost estimates provided in the CEC study referenced earlier. Large associated gas volumes are produced from the Prudhoe Bay field on the Alaskan North Slope, but nearly all of the produced gas is reinjected to assist in oil recovery and due to the current lack of a transportation system to deliver this gas to markets. Additional capital expenditures necessary to make this gas available at the plant gate are minimal. Our analysis suggests that approximately 30 Tcf of gas from Alaska would be available at the plant gate at a direct cost, including a before tax rate of return to the producer, less than $C(1990) 1.00/GJ. To this of course must be added a substantial transportation cost to deliver the gas to markets. Significant additional resources are also anticipated to be available from this region at somewhat higher direct costs, but are not expected to contribute to gas supply over our projection period.

We have not included imports from Mexico in our analysis, as most consultees indicated that supply from this source was not likely to materialize over the projection period. However, some industry consultees were of the view that imports of Mexican gas to the U.S. Gulf Coast region could occur toward the end of the study period.

We conclude this section with a discussion of other supply-related factors which influence supply costs and thereby have an impact on price formation and interregional trade flows. These include direct costs for liquefied natural gas (LNG), certain financial assumptions, the reserves-to-production ratio and backstop costs.

LNG is a potential source of natural gas supply for the North American market and receiving terminals currently exist at Everett, Massachusetts, at Cove Point, Maryland, at Elba Island, Georgia and at Lake Charles, Louisiana. These terminals, which have a total design capacity in the range of 0.8 to 1.0 Tcf per year, were constructed a number of years ago and have been relatively inactive because the delivered cost of LNG has not been competitive with indigenous sources of natural gas supply. We do not anticipate that significant new LNG import capacity will be constructed during this period. The input we received from consultees suggested that a very limited number of deep water ports would appear to be suitable locations for such facilities and that there would be significant siting difficulties for new terminal facilities.

Additional LNG imports will require the construction of new facilities in LNG exporting countries. We believe that generally the new facilities will be viable only if the price of LNG landed in the U.S. increases from current levels. We have assumed that the cost of LNG landed in the U.S. will be approximately 80 percent of the price of crude oil, because those countries supplying LNG are likely to value it as a substitute for oil, while wanting it to penetrate European and North American markets.

The supply costs used in our analysis include a provision for an adequate rate of return to the producer. In order to reflect this in our analytical framework, certain financial assumptions must be made. For the U.S., we have assumed that debt capital could be borrowed at 4 percent real and equity capital at 8 percent real. The U.S. industry is on the whole less leveraged than the industry in Canada, and we have assumed that 80 percent of U.S. investment would be financed with equity and 20 percent with debt. The comparable parameters for Canada, which are discussed more fully in section 7.2.1, are 4 percent real for debt capital, 8 percent real for equity capital and 60 percent of investment financed through equity and 40 percent with debt. The income tax rate is assumed to be 45 percent of taxable income in both Canada and the U.S. Our financial assumptions do not account for any special provisions which could reduce the effective tax rate below 45 percent.

The assumed reserves-to-production ratios (R/P ratios) also affect the direct cost estimates used in our analysis. The R/P ratio indicates the level of reserves, or "inventory", that is being maintained on an ongoing basis relative to production. The lower the R/P ratio, the less the inventory and the lower the "carrying costs" for a particular demand level. Lower R/P ratios therefore tend to reduce supply costs, whereas higher R/P ratios tend to have the opposite effect. For the U.S., the aggregate R/P ratio has been maintained at

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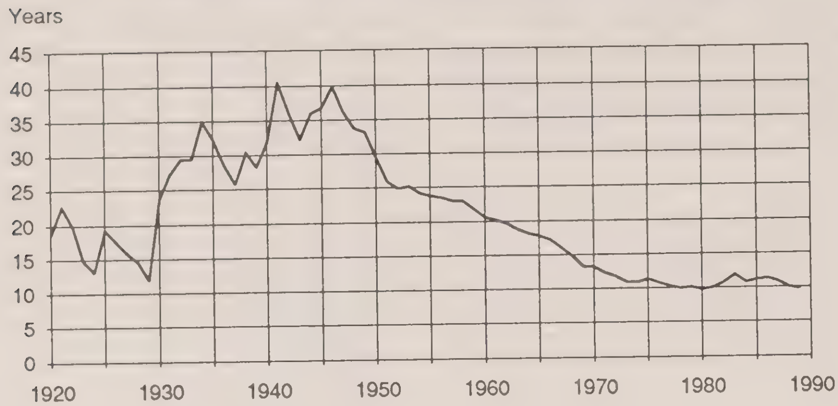
1 P.D. Holtberg, T.J. Woods, M.L. Lihn and N.C. McCabe, *1991 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Gas Research Institute, Chicago, Illinois, 1990.

Figure 6-16

United States Reserves / Production Ratio



approximately 10 for some time (Figure 6-16). We have chosen not to differentiate to a significant degree among supply regions and have assumed that for most U.S. supply regions the R/P ratio will remain at 10 over the projection period. Exceptions to this were made for the Appalachian region, where we considered an R/P ratio in the range of 20 to be more reasonable due to various factors such as low productivity reservoirs, and the Gulf Coast region, where more prolific reservoirs have historically led to an R/P ratio in the range of 6 to 7. We have used an R/P ratio of 7 for the Gulf Coast region in our analysis.

Finally, the analytical framework which we are using requires that a backstop supply cost be specified. A backstop is a supply source from which very large volumes of gas can be made available at costs that remain relatively constant over time. A more extensive discussion of the role of the backstop cost in price formation is provided in section 6.1. We considered various potential backstop supply sources for our analysis, including coalbed methane (at volumes significantly in excess of those postulated by the GRI projection), LNG (at volumes well in excess of the existing terminal capacity), synthetic natural gas from coal and frontier supply. Our analysis suggests that significant volumes from a combination of these supply sources could be made available from various supply regions at direct costs in the order of $C(1990) 7.50/GJ.

The estimation of the backstop cost involves the projection of costs for supply sources which are not expected to significantly contribute to supply until well into the next century. While we have based these backstop costs on informed judgement and input received during the consultation process, and have attempted to incorporate some measure of technological change in the analysis, their estimation remains a rather speculative exercise. The sensitivity of the natural gas price projection to alternative assumptions regarding the backstop cost is discussed in section 6.5.3., where we find that considerable variation in backstop cost does not have a major impact on price formation.

In summary, the estimation of direct costs for the U.S. has a significant impact on the price formation for natural gas in the North American market. Relative costs, particularly between the U.S. and Canada, can have a substantial impact on interregional natural gas flows. While we have endeavoured to use the best publicly available information regarding U.S. costs, to obtain input from knowledgeable industry and government representatives in the U.S., and to reflect some measure of technological change in our analysis, these estimates remain uncertain. The sensitivity cases discussed later in this chapter are therefore important in understanding the potential impact, particularly on price, of alternative views regarding U.S. supply costs.

6.2.5 The Pipeline Network

In this and in the two following sections we discuss the pipeline network, pipeline toll and distribution cost assumptions which we use for the North American natural gas market projections.

The natural gas pipeline network in North America is very large and complex, with numerous interconnections, competing facilities between some delivery and receipt points, and varied technical operating conditions and commercial practices. It is neither possible, nor for our purposes necessary, to have a complete replication of this network in the analysis underlying our gas market projections.

It is nonetheless necessary to have a network representation which is detailed enough to provide a plausible analysis of competing gas flows between those Canadian and U.S. regions important to the international gas trade projections. When using a

model with a network for part of the analysis, insufficient inter-regional network representation could cause important flows to be wrongly allocated between regions or missed altogether.

When using the NARG model to develop trade projections, the analyst may specify either pipeline "corridors", which are single links representing all of the pipelines connecting the same sending and receipt points, or individual pipelines. An example of a corridor is the linkage connecting the Gulf Coast with the East-South Central demand region. An example of an individual pipeline is the TCPL line connecting Alberta with Ontario.[1] One chooses corridors when it is adequate to let one set of toll and capacity data represent that route, or individual pipelines when either there are no competing lines over the same route, or there are competing lines with very different tolls and capacities, and there is interest in analyzing their competitivity. Figure 6-2 shows the pipeline network we use in the NARG model. Appendix Table A6-5 shows in detail how we have chosen to represent all of the routes in our network.

The network includes existing LNG de-liquefaction facilities. It makes no provision for additional facilities, as there is little confidence that local authorities will allow the siting of new plants because of negative public perceptions concerning safety and environmental impacts.

The network consists of existing pipelines and provision for new pipelines. The new pipelines begin to carry gas when it becomes competitive to do so. Examples of new pipelines are the ANGTS, the Mackenzie Valley project, the Altamont and PGT loop projects.

6.2.6 Pipeline Tolls

Having selected the network design, the next set of issues concerns how to represent their capacities and transportation costs. These issues include:

- possibilities and cost of capacity expansion;
- present knowledge of tolls;
- representation of toll structure (that is, demand and commodity charges);
- evolution of the cost of service over time; and
- responsiveness of tolls to market conditions.

The importance of these issues is that tolls do influence the cost of and demand for gas in end-use markets, and comparative transportation costs can influence the flow pattern of natural gas across the continent. For example, transportation costs are of particular importance to Canadian gas flows, given the relatively greater distance to markets than is typical between U.S. supply sources and their markets. That much said, our experience with the NARG model indicates that in the long run, the comparative costs of the gas itself between different supply sources is *generally* the more important factor in determining how much gas flows from particular sources to markets. This happens because as energy values and gas supply costs increase over time, these costs become an increasingly large proportion of total delivered cost.

It is necessary to make assumptions about the **possibility and cost of capacity expansion**, however, we do not have detailed information on the expansion conditions for every pipeline and corridor included in our analytical framework.

The way in which we have addressed this issue is to assume that pipeline capacity can be expanded while maintaining pipeline tolls at constant real levels, unless we have information to the contrary for specific lines. The implicit presumption here is that the costs of expansion offset depreciation of the existing rate base, leaving real tolls at about current levels. Appendix Table A6-6 indicates those pipelines for which we have made exceptional assumptions.

This treatment of tolls is not ideal, because it could overstate or understate the costs of delivering gas over pipelines which would experience either declining or increasing real rate bases respectively, but to which we have assigned constant real values. This in turn could bias the market share of various sources in accessible end use markets.

This leads directly to the issue of portraying the **evolution of the cost of service** over time. If a pipeline were not to expand, over time its rate base is likely to decline. If the tolls were set on a cost-of-service basis, this would lead to declining real tolls over time. In order to portray this process accurately, it would be necessary to model projections of the cost of service of every pipeline in the network. This would require a great deal of information about the current rate bases, what will happen to them in the future, and perhaps most important of all, whether cost-of-service will remain

1 We have included 300 Bcf of "Great Lakes" flows from Alberta to Ontario as part of the TCPL system.

the basis of toll methodology over the long term. We do not have all of this information, and the last item cannot be known with certainty at this time.

Since we do not have the capability to portray profiles of declining rate bases over time, we have substituted this with a more judgmental approach in which we assess which pipelines may experience declining rate bases (using projections of volumes likely to be carried in the future), and for these pipelines we use a constant real toll whose value is a rough average between its current level and the toll which would apply once the rate base is heavily depreciated. This would have the effect of understating some tolls now, and overstating them later in time. This may not impart a major bias to the analysis, because a number of pipelines facing declining rate bases may be already heavily depreciated, and tolls become less important than gas costs as time goes on.

Furthermore, the usefulness of shaping the cost-of-service over time also depends upon the **quality of our present knowledge of tolls**. We have had extensive consultations with pipeline companies and some of their clients, in the course of which we developed an appreciation of the difficulties of establishing representative averages of *today's* tolls. Published toll schedules, while helpful, are not a sufficient basis for developing a realistic portrayal of current transportation costs. For existing pipelines, tolls vary considerably according to the terms and conditions of transportation and in some cases, competitive market conditions. In Pacific Gas and Electric's franchise area (Northern California), transportation and distribution costs are bundled from the state border to the burnertip, while our approach treats transportation and distribution costs separately; therefore we have had to estimate unbundled costs. For future pipelines, there are important instances of debate and uncertainty about what the tolls are likely to be, partly because the answer depends upon how regulators will determine a variety of matters over which they have discretion. Examples include prospective tolls for Altamont, the PGT Expansion and the ANGTS project.

Apart from the *level* of tolls, there is also an issue of **toll structure**, insofar as different pipelines have different methods of recovering costs between demand and commodity charges. While Canadian pipelines generally use the full fixed-variable (FFV) method, in the U.S. they use the modified fixed variable (MFV) method.[1] Some people believe that differences in toll structure between pipelines affects the competitivity of different sources of gas.

A further concern is that toll structures change over time, but predicting the nature and timing of these changes is impossible. Both the companies and their regulators may trigger such changes for a variety of reasons.

We do not attempt to portray toll structure in our work for two reasons. Firstly, it would be extremely difficult to do so with any confidence. Secondly, it is not at all clear to us that toll structure matters much in a long-run projection: in the long term, for pipelines to stay in business they must recover their total costs and earn a normal rate of return; their customers must assess their total costs of transportation over each alternative line because they do pay both demand and commodity charges. In the long run, for new contracts and all old contracts open for renewal, demand charges become future costs rather than sunk costs and it is the blended cost that future shippers will assess. Therefore modelled tolls which blend the demand and commodity cost of transportation should reflect the competitive positions and commercial viability of the various pipelines over a long future time period. Our tolls are average unit costs of transportation, ignoring the demand and commodity charge distinction.

Perhaps the most important issue affecting future tolls is **their responsiveness to market conditions**. While tolls have been regulated for many years largely on a cost-of-service basis with little flexibility to respond to market conditions, this is now changing. The FERC allows pipelines operating under optional expedited certificates or MFV rate design to discount tolls within a certain range in order to compete for volume. Their overall rate of return remains regulated. This kind of toll discounting now happens on a rather limited and seasonal basis, but it may presage a more general and gradual evolution toward market-responsive toll mechanisms - especially where it could be advantageous to let the market allocate volumes between competing sources and transporters. This is not yet in place and we do not accommodate it.

Because our tolls are long-term average values, we cannot portray seasonal and short-run variations in volumes over specific links. We do not believe that this limitation

1 These methods represent alternative ways of structuring the "demand" and "commodity" components of the toll.

seriously distorts a long-term projection of the changing structure of gas flows because, over a period of several years, on average each pipeline must earn its rate of return or face some form of commercial adjustment. On a longer-term basis, our results do indicate which links may experience commercial difficulties, because they fail to capture the volumes on which their tolls were predicated. In this sense, our projections may prolong the use of certain links which would either cease to operate in reality, or, if they were to continue operating, require a more rapid writing-down of the rate base to accommodate competitive tolls.

Given this background on the key issues, we summarize how we specified pipeline tolls in the work we did using the NARG model:

1. On the basis of extensive consultation with a number of pipelines, customers and governmental agencies, we developed specific, unchanging long-term average pipeline tolls for each link, taking account of currently expected expansion or depreciation of the rate base, unless we had more specific information about the extent to which tolls would escalate with capacity expansion.

2. For those latter cases we apply a toll multiplier which escalates the toll according to the extent of incremental capacity, capped at some level reflecting the maximum expected overall real escalation of the toll. In this respect, the escalated tolls apply to all volumes, and are to be interpreted as "rolled-in" rather than "incremental". The NARG model then finds the volumes which are competitive as tolls increase on these links.

3. For major new pipeline proposals (for example, the ANGTS and Mackenzie Valley pipeline) we use a cost-of-service approach; for ANGTS we averaged the first 10 years' cost of service and from then onward used the remaining cost of service in order to portray long-run average capital charges. For Mackenzie Valley we used a long-run average cost of service. (We recognize that actual tolling arrangements will be more complex when these projects begin to operate.)

4. In those cases where we had competing information about pipeline tolls, we tested the impact of alternative views on resulting volumes, and compared these alternative estimates with available commercial information, in order to find the toll assumption providing the closest approximation between model results and commercial information. While useful, this approach has limitations where the sum of competing commercial expectations can exceed the likely size of the market.

To conclude, it is necessary to make simplifying assumptions in an aggregate analysis of this nature, and we have obtained extensive input from knowledgeable sources in order to develop toll estimates which are as reasonable as possible, given the evident limitations. Small variations of toll assumptions are not likely to have a large impact on the overall size of the natural gas market or on the natural gas price projections, but different relative toll assumptions can affect the relative size of flows over related corridors, affecting the market shares of corresponding supply sources.

6.2.7 Distribution Margins

Some of the issues we discussed above regarding pipeline tolls also apply to distribution margins - specifically, present knowledge of margins, evolution of the cost of service over time, and the responsiveness of margins to market conditions.

For U.S. distribution margins, we generally relied upon information provided with the 1991 GRI Baseline Projection. For Canadian distribution margins, we used in-house data, developed as explained in Section 3.1. We generally specified very low distribution charges for the industrial and electricity generation sectors, expecting that over time these margins may have to be compressed as low as commercially feasible in order to meet competition from fuel oil in the readily-switchable end-use markets, given our Control Case and low oil price sensitivity case projections. Our distribution margins are listed in Appendix Table A6-7.

Our distribution margins remain the same in real terms over the period of the analysis. In this respect, they are not as market responsive as they may have to become in reality, nor do they reflect the pattern of change in the rate bases of the local distribution companies. This may impart some upward bias to distribution costs later in the outlook period, but given the low sensitivity of natural gas demand to price in the "core" market, and the initial setting of very low distribution margins in the price-sensitive sectors, we think that our results are broadly indicative of what would occur if we had a more accurate portrayal of changing distribution margins over time.

6.2.8 Oil Prices and Constraints on the Use of Oil

Up to 2010, the crude oil price assumptions are those of Section 2.1.[1]

In our projections, heavy fuel oil (HFO) and light fuel oil (LFO) are substitute fuels for natural gas in the electricity generation demand sector and HFO is the substitute fuel in the industrial sector. We developed our HFO and LFO prices on the basis of the crude prices mentioned above.

HFO represents Nos. 4, 5 and 6 fuel oil and LFO represents No. 2 fuel oil. Delivered HFO and LFO prices to end users in each region are based on the crude oil price projections in Section 2.1. We assumed an HFO:crude oil price ratio of 0.95 (by volume) as representative of a long-term price relationship; the HFO:crude ratio has in the past exhibited considerable variability, ranging from about 0.75 to over 1.0.

On the basis of discussions with consultees, a $US(1990) 0.75/bbl environmental premium was added to all Canadian and U.S. HFO prices to represent the increased cost of obtaining low sulphur fuel oil or desulphurizing high sulphur fuel oil. In addition, HFO prices in California and the U.S. Northeast were set equal to the price of LFO, to reflect more stringent environmental regulations in these regions. In the southern California region, where environmental regulations are particularly stringent, HFO use is phased out by 1997 and LFO use is restricted to 5 percent of the gas/LFO market by 1997.

Table 6-8 shows the prices used for HFO and LFO in Canada and the U.S.

Table 6-8

Oil Product Prices for the Natural Gas Market Analysis

($C 1990/GJ)

	1989	1992	1997	2002	2007	2012
Canada						
LFO	8.00	7.45	8.01	8.38	8.81	9.17
HFO - Noncore	3.02	3.50	3.99	4.22	4.44	4.60
HFO - Electricity Generation	3.02	3.50	3.99	4.22	4.44	4.60
U.S.						
LFO	5.10	6.06	6.69	7.06	7.32	7.33
HFO - Noncore	3.04	3.63	4.47	4.46	4.59	4.73
HFO - Electricity Generation	3.04	3.77	5.55	5.01	4.82	4.86

Note: Years shown correspond with reporting years from the NARG model analysis (see Section 6.4)

6.2.9 U.S. Demand

To determine market-clearing prices using the NARG model, it is necessary to begin the analysis with an initial demand estimate. The price determination process subsequently adjusts this demand taking account of our oil price, supply and transportation assumptions, which may differ from those underlying the initial demand estimate. We discuss the initial U.S. demand estimate in this section, and the U.S. demand projection resulting from our analysis in Section 6.4.2.

In order to estimate U.S. demand for natural gas, we begin with the Gas Research Institute 1991 Baseline Projection.[2] The GRI Baseline provides considerable sectoral and regional detail and has a large amount of supporting information which is most useful to understanding the factors underlying the results.

Table 6-9 shows the components of the 1991 GRI Baseline Projection relevant to our analysis.

The total projected gas plus oil demand grows strongly between 1989 and 2010, from 21.1 to 29.7 Tcf/year, with the oil share increasing from 2.2 to 7.1 Tcf - equivalent.

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1 When using the NARG model, the period of the analysis extends to 2032. Beyond 2010, we stabilized the low case real oil price at the 2010 level, and allowed the Control Case and high case oil prices to reach about (U.S. 1990) $42/bbl, by 2032, which is equivalent to our backstop natural gas value of about (Cdn 1990) $8.30/GJ.

2 P.D. Holtberg, T.J. Woods, M.L. Lihn, and N.C. McCabe, *1991 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Gas Research Institute, Chicago, Illinois, 1990.

Table 6-9

1991 GRI Baseline Projection
U.S. Gas and Oil Demand Inputs

(Tcf/Year)

	1989			2000			2010		
	Gas	HFO	LFO	Gas	HFO	LFO	Gas	HFO	LFO
Residential	4.8			4.6			4.4		
Commercial	2.6			2.6			3.0		
Cogeneration	0.2			0.5			0.7		
Total Commercial	2.7			3.1			3.7		
Feedstock	0.6			0.6			0.5		
Industrial	5.5	0.6		5.2	1.8		5.7	2.8	
Cogeneration	0.7		0.1	1.2		0.2	1.4		0.3
Total Industrial	6.2	0.6	0.1	6.4	1.8	0.2	7.2	2.8	0.3
Utility Generation	2.7	1.4	0.1	4.0	2.5	0.4	4.7	3.2	0.7
Lease/Plant and Pipeline Fuel	1.8			1.9			2.2		
Total	**18.9**	**2.0**	**0.2**	**20.5**	**4.3**	**0.5**	**22.6**	**6.0**	**1.1**

Source: 1991 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010, Gas Research Institute, 1990
Note: Totals may not add due to independent rounding.

During the 1989 to 2010 projection period, natural gas demand grows moderately by 3.7 Tcf, from 18.9 to 22.6 Tcf/year. HFO demand which is considered switchable with gas increases by a similar amount, from 2.0 Tcf/year in 1989 to 6.0 Tcf/year by 2010. LFO demand which is considered switchable with gas continues to have a minor role in these markets, increasing by only 0.9 Tcf from 0.2 Tcf/year in 1989 to 1.1 Tcf/year in 2010.

Between 1989 and 2010, residential gas demand is projected to decline from 4.8 to 4.4 Tcf/year as efficiency improvements outstrip market growth. Over the same period, growth occurs in commercial gas demand from 2.7 to 3.7 Tcf/year, primarily in cooling and cogeneration markets. Dry gas feedstock demand (e.g. for petrochemicals) is expected to remain relatively flat throughout the period at 0.5 to 0.6 Tcf/year.

Industrial gas use grows from 6.2 Tcf/year in 1989 to 7.2 Tcf/year by 2010. Much of the increase is for cogeneration, but also includes process applications where clean burning fuels provide a quality advantage. Lower cost heavy fuel oil is expected to erode the gas share in industrial fuel and power and in remaining process applications. By 2010, the HFO share of the industrial market is expected to triple - from 9 percent to 27 percent.

Approximately 3.2 Tcf of the 3.7 Tcf increase in gas demand from 1989 to 2010 is associated with the generation of electricity. Of this 3.2 Tcf growth, 2 Tcf is used by utilities and independent power producers, while 1.2 Tcf is used by co-generators. The large increase in electric generation gas demand occurs as electricity demand growth stimulates the construction of gas-fired generation plants. Of the projected 2.0 Tcf/year increase (2.7 Tcf/year in 1989 to 4.7 Tcf/year in 2010) in gas demand for utility/IPP generation, about 0.4 Tcf is anticipated for emission control applications in coal-fired power plants. Heavy fuel oil is expected to supplant gas in much of the steam turbine genera-

tion market as natural gas prices increase.

The GRI projection includes vehicle fuel demand for natural gas of up to 155 Bcf in 2010, and does not expect stronger growth unless more aggressive penetration of methane vehicles outside of the fleet market is pursued. The NARG model does not explicitly model vehicle transportation uses for natural gas, but we include this volume in the estimate of lease, plant and pipeline fuel.

The GRI projection does not include certain Iroquois project gas volumes which will displace fuel oil in the residential sector and coal and HFO in the industrial sector. To account for the impact of the Iroquois Project, we added gas volumes of 200 Bcf/year to our estimate of the U.S. Northeast market.

We further modified the GRI projection of gas-fired and oil-fired electric generation to take account of some suggestions from other U.S. consultees. As a result of shrinking utility reserve margins, all gas-fired steam turbine electric generation facilities (switchable to HFO) are assumed to be life-extended and continue to operate at existing levels. All remaining growth in gas-fired electric generation we assume to involve combustion turbine and combined cycle units due to the superior efficiency of these technologies. To account for environmental considerations beyond those included in the 1991 GRI Projection, we reduced or eliminated any decreases forecast by GRI in gas-fired electric generation by limiting corresponding increases in coal or nuclear-fired generation. This increases our projected gas demands for electric generation by up to 175 Bcf/year above the GRI projection.

For our purposes, it was necessary to reclassify GRI's sectoral data into the different sector definitions which we use in the NARG model. In this model, U.S. demand is analyzed according to U.S. census regions, with some further disaggregation of the California market. Within each demand region, we separate the market into four segments according to our assumptions about fuel switching capability and alternative fuel choices. These market segments are: a core market devoted to gas, a non-core market switchable between gas and HFO, an electric generation market switchable between gas and HFO and an electric generation market switchable between gas and LFO.

The core market consists of natural gas consumers who cannot readily switch to alternative fuel sources; this includes dry gas feedstock for petrochemicals, and residential and commercial non-cogeneration gas uses. Core consumers are restricted to the use of gas either by process requirements or because of the unattractive capital costs associated with acquiring fuel switching technology, given the range of LFO prices in our projections.

We disaggregated the electricity generation market for natural gas according to two broad classes of technologies. Steam turbine generators are assumed to be switchable between gas and HFO. Combustion turbine and combined cycle generators are assumed switchable between gas and LFO. Commercial and industrial cogeneration consists of producing electricity as a byproduct of other commercial or industrial activity using steam. As most cogeneration uses combined cycle technology, it is included in the market segment switchable between gas and LFO. We provide in Annex 3 a more detailed description of how we allocated natural-gas using electricity generators between LFO or HFO switchability.

Table 6-10 shows our modified version of the 1991 GRI Baseline Projection disaggregated into demand sectors relevant to interfuel competition as structured in the NARG model.

Within the core market, residential gas demand is projected to decline as efficiency improvements outstrip market growth. Non-cogeneration commercial gas demand is projected to experience moderate growth mainly due to cooling applications.

The non-core market includes all industrial non-cogeneration customers, using either natural gas or HFO, who are assumed to be able to switch between the two fuels. In the non-core market, anticipated moderate increases in industrial gas use mainly involve process applications where clean burning fuels provide a quality advantage. Lower cost heavy fuel oil is expected to significantly erode gas share in industrial fuel and power and other process applications.

All growth in gas demand for electric generation is projected to occur in the market switchable between gas and LFO. Approximately 60 percent of the projected increase is attributable to strong growth in independent power production and in commercial and industrial cogeneration. Another 8 percent of the increase is anticipated for emission control applications in coal-fired power plants.

Gas demand in electric generation markets switchable between gas and HFO is projected to remain at

Table 6-10

NEB Projections of U.S. Gas and Oil Demand Inputs for Use in NARG Analysis

(Tcf/Year)

	1989			2000			2010		
	Gas	HFO	LFO	Gas	HFO	LFO	Gas	HFO	LFO
Core	8.0			8.0			8.1		
Noncore	5.5	0.6		5.2	1.8		5.8	2.8	
Electric Generation									
Gas/HFO Switchable	2.6	1.4		2.5	2.5		2.5	3.2	
Gas/LFO Switchable	1.1		0.2	3.3		0.5	4.5		1.1
Total Electric Generation	3.7	1.4	0.2	5.8	2.5	0.5	7.0	3.2	1.1
Lease/Plant and Pipeline Fuel	1.8			1.9			2.2		
Total	**19.0**	**2.0**	**0.2**	**20.9**	**4.3**	**0.5**	**23.0**	**6.0**	**1.1**

Source: National Energy Board, 1991, based on the 1991 GRI Baseline Projection as modified by NEB staff.
Note: Totals may not add due to independent rounding.

current levels as gas-fired steam turbine facilities are life-extended. The gas share of this market is expected to decline over time as gas prices rise relative to HFO prices.

The GRI projection is based on world oil price assumptions which differ considerably from ours beyond the year 2000: GRI has higher world oil prices over this time period (See Chapter 2). We discuss the consequences of this difference to our U.S. demand results in Section 6.4.2.

6.2.10 Canadian Demand

As in the case of U.S. demand discussed in the previous section, it is also necessary to begin the analysis with an initial Canadian demand estimate. We used the low case demand projection from the Board's 1988 Report for this purpose. This projection, and the Canadian demand projections for this Report are derived using the Board's Energy Demand Model (EDM), because EDM has a more comprehensive portrayal of Canadian demand than that in NARG. We subsequently iterate between EDM and NARG to achieve consistency of prices and resulting demand, as discussed in Sections 6.4.1 and 6.4.5 respectively.

6.3 Rationale and Description of Cases

In the Control Case, oil prices and natural gas supply costs are about in the middle of the range which we consider plausible.

As mentioned in Chapter 1, projected natural gas market conditions are particularly sensitive to the assumptions one makes about world oil prices and North American supply costs of natural gas. As both of these factors are subject to great uncertainty, especially given the long time horizon used in this study, we considered it essential to develop a range around our key Control Case results with respect to different oil price and gas supply cost assumptions.

The oil price affects natural gas demand mainly in the fuel-switchable markets, which in turn affects the rate of progression from lower to higher cost gas supply, hence the price of natural gas, and overall demand levels consistent with these prices. For example, at oil prices higher than in the Control Case, demand for natural gas is higher, causing more rapid progression to higher cost gas supply and higher natural gas

prices. The reverse conditions apply when oil prices are below Control Case levels.

Gas supply costs have a direct bearing on natural gas prices and hence on demand and on international trade flows. Particularly important in an international trade context, it is the relative supply costs between competing sources in Canada and the U.S. which have the greatest effect on the volumes of gas exports and imports. Assumptions regarding backstop costs also influence the natural gas prices arising from our analysis.

In our sensitivity tests, we have used a range of ultimate recoverable resource potential to derive the range of supply costs used in the analysis. However, there are other factors which could give rise to higher or lower supply costs than those used in the Control Case, as discussed in Section 6.2.2.

These considerations led to the development of seven cases:

1. Control Case

2. Control Case resources with high oil prices

3. Control Case resources with low oil prices

Control Case oil prices with:

4. Control Case U.S. resources and high Canadian resources

5. Control Case U.S. resources and low Canadian resources

6. high U.S. and high Canadian resources

7. Control Case resources and lower backstop value for natural gas.

The main purpose of cases 2, 3, 6 and 7 is to observe the impact of changed assumptions on natural gas prices and demand, and that of cases 4 and 5 the impact on Canada's international natural gas trade of higher and lower Canadian resource potential and related changes in supply cost.

Table 6-11 shows the crude oil price range and natural gas resource estimates used in each of these cases. Although we show only the range of resource estimates for the WCSB and U.S. Lower-48 States, we have included

Table 6-11

Description of Natural Gas Cases[a]

Case	Canadian Resource[b] (EJ)	U.S. Resource[c] (Tcf)	Oil Price ($1990 U.S./bbl)	Description
1	250	1415	20 - 27	Control
2	250	1415	22 - 35	High Oil Price
3	250	1415	18 - 20	Low Oil Price
4	200	1415	20 - 27	Low Canadian Resource
5	300	1415	20 - 27	High Canadian Resource
6	300	1701	20 - 27	High North American Resource
7	250	1415	20 - 27	Low Backstop ($5.00 C 1990/GJ)

[a] The purpose of this table is to show the key parameters changed in the sensitivity cases relative to the Control Case.
[b] Canadian resource estimates included in this table are for the WCSB only.
[c] U.S. resource estimates included in this table are for the Lower-48 states only.

the Canadian frontier regions and Alaska in these analyses. The resource estimates shown are ultimate recoverable resource potentials.

6.4 Control Case Results

In this section, we discuss the Control Case results, starting with natural gas prices, then U.S. demand and supply, Canadian exports and imports and Canadian demand and supply. We then discuss the key findings emerging from the sensitivity cases, followed by a summary of results. For those results which have as their basis the NARG analyses, we use the reporting years in the NARG model, which start with 1987 and report at five-year intervals thereafter. Our final year for this report is 2010; therefore, we report results to 2012 in the NARG series.

6.4.1 Fieldgate Prices and Selected Regional Prices

Table 6-12 shows the progression of Control Case natural gas prices between 1989 and 2012.

The main observations from the price data in Table 6-12 are:

1. Between 1989 and 2002 the real Alberta fieldgate price increases by about 5.5 percent per year, whereas Lower-48 prices increase by 4.2 percent per year. Thereafter, to 2012, Alberta and U.S. fieldgate prices both increase by about 3.4 percent per year.

2. Alberta fieldgate prices are below Lower-48 fieldgate prices throughout the projection; however, the percentage difference narrows beginning in the late 1990s. While the Alberta price is about 73 percent of the Lower-48 price in 1989, it is 80 percent in 1997 and about 85 percent from 2002 onward. Part of the difference between Alberta and Lower-48 fieldgate prices is due to the fact that there is a lower average pipeline transportation cost wedge between Lower-48 U.S. resources and markets than is the case for Canada. Furthermore, in the early years, Canada has a larger supply overhang than does the U.S. There are commercial and transportation constraints to the rapid convergence of regional supply, demand and prices across the continent. As the Canadian supply overhang dissipates, fieldgate price differences narrow and reflect mainly transportation cost differences.

3. Retail prices (core and non-core delivered prices) also increase, but by much less than fieldgate prices, because the transportation and distribution margins are generally fixed in real terms. (These retail prices are national averages, which embody any change in the regional composition of demand over time).

Figure 6-17 shows the Alberta fieldgate price projections for the Control Case and the two oil price sensitivity tests discussed in section 6.5.1 below.

Figure 6-18 shows our range of U.S. Lower-48 natural gas fieldgate price projections compared with recent projections done by the AGA, EIA and GRI. On the whole, our Control Case and high oil price case gas price projections for the Lower-48 are very close to those of the AGA and the EIA until the mid-1990s. All of these projections

Table 6-12

Selected Control Case Natural Gas Prices

($C 1990/GJ)

	1989[a]	1992	1997	2002	2007	2012
Lower-48 Fieldgate	2.09	2.24	2.91	3.56	4.23	4.99
Alberta Fieldgate	1.52	1.41	2.35	3.04	3.62	4.24
Core Market Canada	4.44	4.68	5.00	5.67	6.22	6.75
Noncore Market Canada	2.47	2.94	3.58	4.20	4.69	5.27

[a] Actual

Figure 6-17
Natural Gas Price Projection
Alberta Fieldgate
($C 1990/GJ)

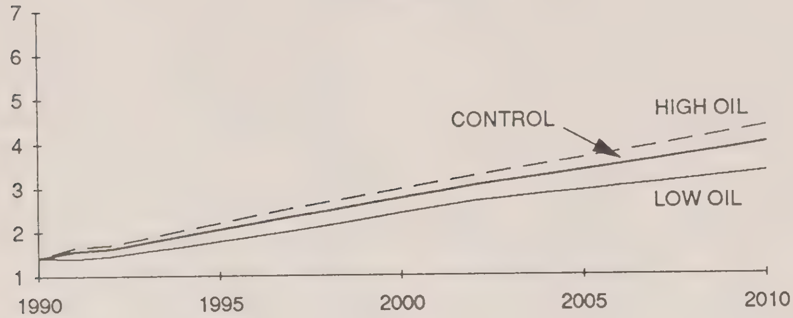
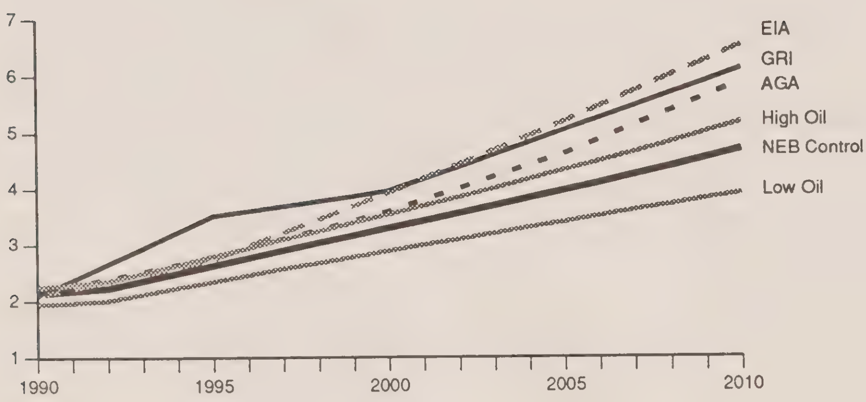


Figure 6-18
Natural Gas Price Projection
U.S. Lower-48 Fieldgate



are considerably below the GRI projection for this time period.[1]

Our Control Case beyond the mid-1990s and low oil price case gas price projections are generally below the others, while our high oil price case projection resembles the AGA to 2000, and lies below thereafter. There may be a number of reasons for these differences, including different assumptions and modelling frameworks. Detailed comparisons would be arduous, but we provide some explanation of these different results in Section 6.4.2.

Figure 6-19 shows a comparison of our Control Case fieldgate natural gas prices and the base case results obtained in two recent Canadian Energy Research Institute (CERI) studies and a Wharton Econometric Forecasting Associates (WEFA) study.[2] The NEB Control Case fieldgate price path is below those of CERI throughout the time period of the projection, while WEFA's prices are below ours till the late 1990s, but grow considerably higher till about 2007, after which they tend

1 *A.G.A. - TERA 1989 Mid-Year Base Case*, American Gas Association, Arlington, Virginia, 1989. *Annual Outlook for Oil and Gas 1990*, Energy Information Administration, Washington D.C., *1990.* P.D. Holtberg, T.J. Woods, M.L. Lihn, and N.C. McCabe, *1991 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Gas Research Institute, Chicago, Illinois, 1990.

2 L.A. Coad and D.H. Maerz, *Continental Natural Gas Market Canadian Export Capacity in the 1990s*, Canadian Energy Research Institute, Calgary, Alberta, October 1989. D.H. Maerz and L.A. Coad, *Markets for British Columbia Natural Gas*, Canadian Energy Research Institute, Calgary, Alberta, November 1990. *Regional Natural Gas Markets in North America to the Year 2020*, the WEFA Group Energy Services, Fall 1990.

Figure 6-19
Natural Gas Price Projection Alberta Fieldgate
($C 1990/GJ)

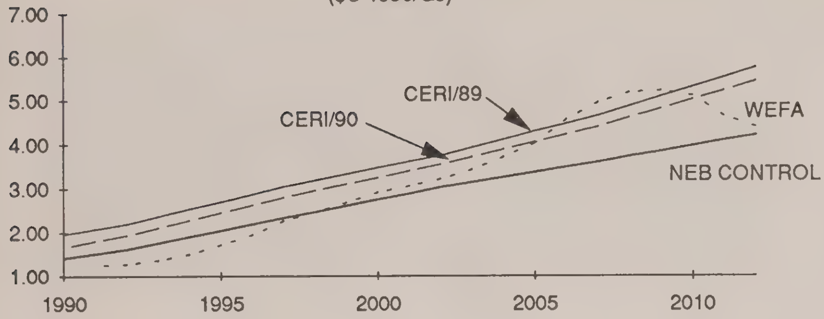


Figure 6-20
Fieldgate Natural Gas Prices: Control vs 1988 Report
($C 1990/GJ)

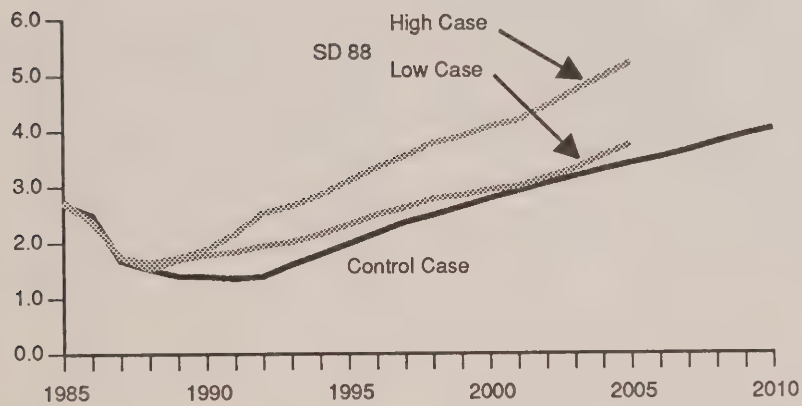
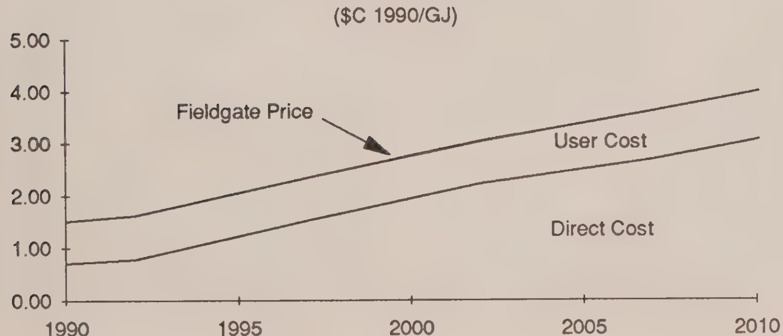


Figure 6-21
Alberta Natural Gas Fieldgate Price Components
($C 1990/GJ)



downward toward the NEB control value by 2010.

Figure 6-20 shows our Control Case price projection relative to those in the 1988 Report. The present Control Case price is below the 1988 Low Case over the next ten years, but follows it quite closely from the late 1990s onward.

On the whole, during our consultations we found the natural gas industry to be rather skeptical of the extent of price increases shown in any of these projections. We received comment to the effect that over the next few years, short-term factors will dominate price - specifically, that the current supply overhang and slow demand growth will prevent prices from growing to the extent our projections indicate, influenced as they are by longer-term cost and value considerations. (Figure 6-21 provides additional insight into fieldgate price formation.) For the longer term, it would take considerably more optimism about supply costs than we have assumed, in order to produce substantially lower growth rates of natural gas prices. This in turn implies more optimism about the size of the resource base and the rate of technological progress in discovering and developing it more efficiently. We acknowledge that there is much uncertainty about both of these factors, and it is possible that the plausible fieldgate price range could be wider than that portrayed in this report. It is also possible that fieldgate prices will not grow to the extent that our and other projections indicate in the near term.

In Section 6.1, we described how the fieldgate price formation process takes into account both the incremental direct cost of supplying natural gas, as well as the "user cost". We mentioned that

the user cost constitutes the "surplus" out of which the resource owner may extract a royalty. In practice, royalties are not calculated on this basis. Royalties today are a smaller proportion of fieldgate prices than indicated by these user costs. This difference between user cost and royalties is a return to producers on previously invested capital, insofar as the direct costs shown for the early 1990s are the operating costs of producing readily producible reserves and exclude a return to sunk capital. Over time, in our results the proportion of user cost to fieldgate price decreases. It is not known now what provincial governments' royalty policies will be in the future; therefore we adopt the "user cost" approach to indicate what royalties would be if one accepted both the economic argument that royalties should be equivalent to user cost, as well as the assumptions underlying the value of these user costs.

This graph shows the approximate composition of the Control Case Alberta fieldgate price as between incremental direct cost and user cost.

6.4.2 U.S. Demand

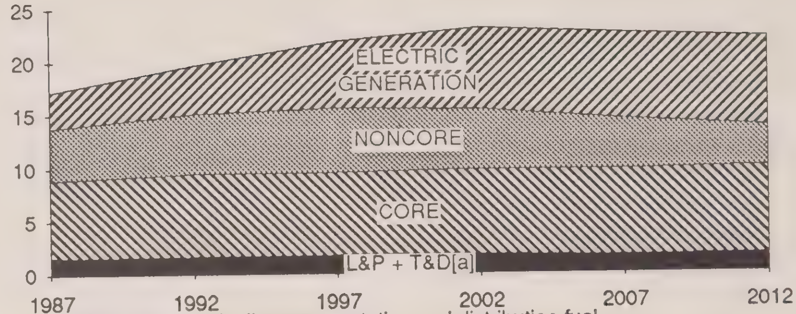
Our U.S. demand results differ from the GRI Baseline projection we started with (see Section 6.2.9) because our oil prices differ from GRI's and we introduced several other modifications to the GRI Baseline, also discussed in Section 6.2.9.

The U.S. gas demand projection resulting from our Control Case analysis is shown in Figure 6-22. Primary gas demand increases from 17.2 Tcf in 1987 to 23.1 Tcf in 2002 before declining to 22.1 Tcf in 2012. The rise and subsequent fall in gas demand is largely explained by the relative costs of

Figure 6-22

Control Case Projection of U.S. Gas Demand

(Tcf/Year)



[a] Lease, plant, pipeline transportation and distribution fuel

gas and HFO in the non-core market. Until 2002, gas demand increases relative to that of HFO because gas prices are well below those of HFO. By 2002, gas and HFO prices are about the same, after which gas prices increase to about 25 percent above HFO prices by 2012. As shown in Figure 6-23, non-core U.S. gas demand increases from 4.9 Tcf in 1987 to 6.0 Tcf by 1997, after which it declines to 3.8 Tcf by 2012. Figure 6-23 also shows a broadly similar picture for Canada.

Because we have assumed that gas demand in the core market is non-switchable, it remains about the same as in the GRI projection, reaching 8.0 Tcf by 2010.

The electric generation market segment in which gas competes with LFO contains the utilities' combustion turbine/combined cycle market, IPP and cogeneration sectors. Gas demand in this market exhibits strong growth from 0.8 Tcf in 1987 to 5.3 Tcf in 2012. Growth in this sector is mainly due to the price of LFO being higher than that of gas in all years of the outlook period, and to restrictions on the use of oil in California. As a result, the share of gas in this market increases from 86 percent in 1987 to 96 percent in 2012. This market segment grows from 5 percent of total gas demand in 1987 to 24 percent in 2012.

The electric generation market segment which competes with HFO is less sensitive to the relative increase in natural gas prices, mainly because of regional restrictions on the use of oil. Hence, compared with the non-core market, beyond 2000 this market erodes only very moderately as the price of gas exceeds that of HFO. This market grows from 2.6 Tcf in 1987 to 3.8 Tcf in 2002, then recedes to 3.1 Tcf by 2012.

This projection assumes no constraints on gas deliverability to electric power plants. There is some uncertainty about this assumption, insofar as residential, commercial and power plant gas demands may all peak at the same time, and it is expensive to reconfigure delivery systems for an increasingly "peaky" load profile. Because our analysis ignores natural gas price spikes or deliverability constraints which could occur during any year, there could be some upward bias in our estimates of annual market size.

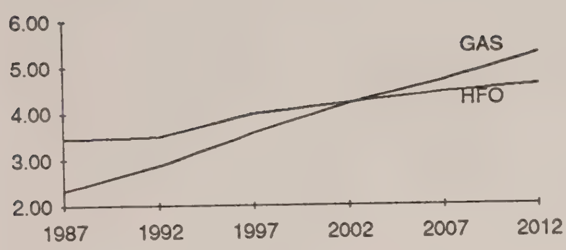
Figure 6-23

Control Case

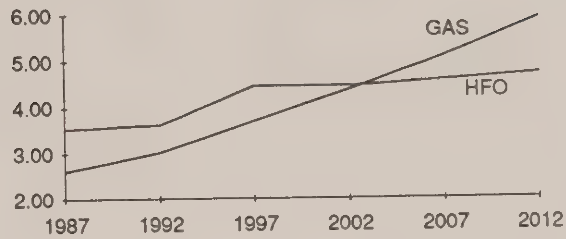
Noncore Gas and HFO Prices

($C 1990/GJ)

Canada



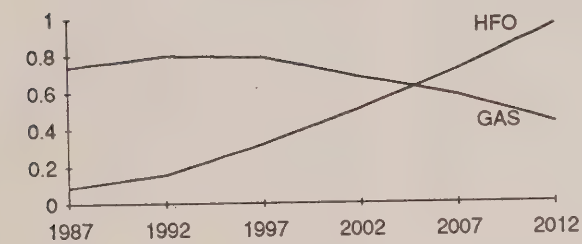
United States



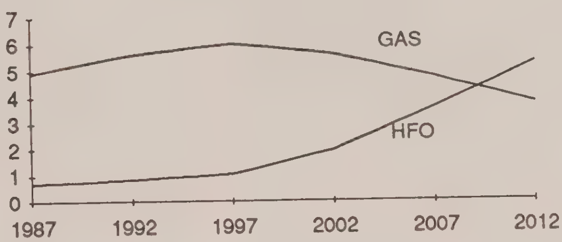
Noncore Gas and HFO Demand

(Tcf/Year)

Canada



United States



Note: Prices are at the point of end-use

Of the 5.0 Tcf increase in gas demand for electric generation by 2012, approximately 2.6 Tcf occurs in the New England, Middle Atlantic and South Atlantic regions. This occurs because of an anticipated decline in electrical capacity reserve margins, due to load growth and plant retirements. Furthermore, oil prices are relatively high in the North East compared with other major demand centres in the U.S.

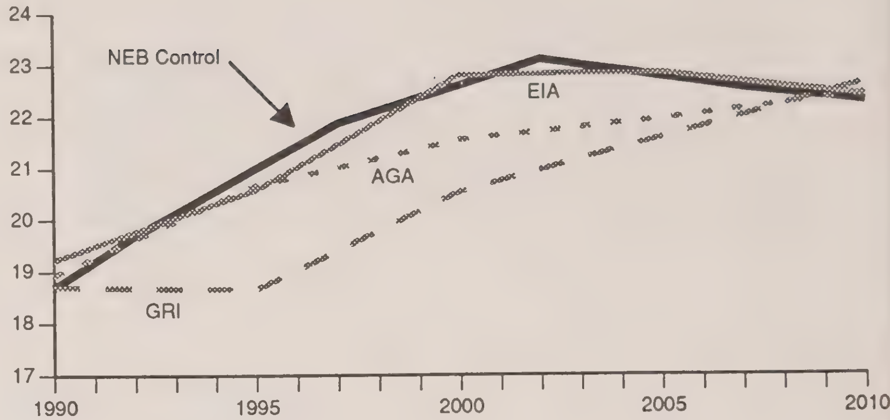
HFO consumption in the total U.S. industrial and electric generation markets increases from 1.8 Tcf equivalent in 1987 to 7.9 Tcf equivalent in 2012 (about equal to 0.8 MMbbl/day in 1987 and 3.6 MMbbl/day of oil in 2012). Most of the increase occurs after 2002, when gas prices rise above HFO prices. The main growth in HFO demand occurs in central U.S. regions, where gas previously had the larger market share.

In our projections, the HFO price is very close to the crude oil prices, as explained in Section 6.2.6. The HFO:crude price relative is an important assumption, but subject to uncertainty. Had we used a lower relationship of HFO:crude prices, the erosion of the natural gas share of non-core markets would have been greater, and the growth of oil use even higher.

Comparison with Other Projections

The main long-term projections of U.S. demand in the public domain are provided by the Energy Information Administration of the U.S. Department of Energy (EIA)[1], the American Gas Association (AGA)[2] and the GRI[3]. The projections incorporate different input assumptions and modeling methodologies and are therefore not directly comparable. However, a comparison of inputs and results provides general insights into expectations of gas market behaviour.

Figure 6-24
U.S. Natural Gas Demand
(Tcf/Year)



A comparison of the projections of total U.S. gas demand is shown in Figure 6-24. The NEB projection of total U.S. gas demand is similar to that of the EIA, and higher than those of both the AGA (beyond 1992) and the GRI until 2010. By 2010, all projections converge at approximately 22.5 Tcf per year.

In aggregate, relative to the NEB Control Case, the GRI projection of gas demand increases more slowly, to be 2.3 Tcf below the NEB projection by 1995 and gradually converges with NEB by 2010. This difference in growth patterns between the two projections happens partly because GRI's oil prices are below the NEB's in the earlier years and above in the later years of the projection. Furthermore, the NEB assumes higher growth than does GRI of natural gas use for power generation early in the projection period, as we assume life-extension rather than retirement of existing generation capacity which is switchable between oil and gas.

The EIA projection of total U.S. gas demand is similar to the NEB projection. However, the sectoral composition of demand growth differs considerably between them. Part of the difference may be due to definitional differences in the composition of the sectors, while other factors causing different sectoral results include different oil prices, environmental and behavioural assumptions.

The AGA projection of total U.S. gas demand is below the NEB projection and mid-way between the EIA and GRI projections for much of the projection period, but approaches the NEB projection by 2010. Part of the explanation for the different growth patterns between the projections may be that the AGA has a non-core gas price approximately 5 percent higher than the HFO price until 2000 before going to 10 percent lower than the HFO prices by 2010. Contrary to the AGA assumption, NEB gas prices are generally *below* HFO prices early in the period and *above* later in the period.

6.4.3 U.S. Supply

In the preceding section we discussed our projection of U.S. demand and compared our results to other projections available in the public domain. In this section we provide an overview of the composition of U.S. supply over the projection period in order to provide a perspective on the role that net imports from Canada might play in satisfying U.S. demand, as compared to other available supply sources. We discuss the contribution of conventional and unconventional produc-

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1 *Annual Outlook for Oil and Gas 1990*, Energy Information Administration, Washington D.C., 1990.

2 *A.G.A. - TERA 1989 Mid-Year Base Case*, American Gas Association, Arlington, Virginia, 1989.

3 P.D. Holtberg, T.J. Woods, M.L. Lihn, and N.C. McCabe, *1991 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Gas Research Institute, Chicago, Illinois, 1990.

tion from the Lower-48 States, in aggregate and on a regional basis, Alaskan production, LNG imports, Mexican imports and net Canadian imports to the total U.S. natural gas supply. Table 6-13 provides a breakdown of the components of U.S. natural gas supply over the projection period.

Lower-48 production is projected to increase to about 20 Tcf per year in 2002 and to decline thereafter to approximately 18 Tcf per year in 2010. The Gulf Coast region progressively declines in terms of annual production over the projection period, to approximately 7 Tcf in 2010 (40 percent of Lower-48 production). Growth in production occurs in the Appalachian region (4 percent of Lower-48 production in 2010) and in the Rocky Mountain region (12 percent of Lower-48 production in 2010). Production from the Anadarko and Permian regions remains relatively constant over the period, both in terms of production levels and percentage contribution to Lower-48 production.

These Lower-48 production estimates include both tight gas and coalbed methane. For the reasons noted in section 6.2.3, we are not able to specifically isolate the extent to which tight gas is included in the PGC resource estimates and therefore cannot provide a specific estimate of the tight gas production included in these supply projections. Coalbed methane production is expected to increase continuously over the projection period, to 0.5 Tcf per year by 1997 and to 1.2 Tcf per year by 2010. The coalbed methane production estimates are based largely on analysis conducted by the Gas Research Institute and include supply from the San Juan, Black Warrior and Appalachian Basins.

Large volumes of associated gas are currently produced in Alaska from the Prudhoe Bay field on the North Slope, but nearly all of the produced gas is reinjected to assist in crude oil recovery. This influences its opportunity value to the producer. Annual sales gas production is currently at very modest levels (about 0.2 Tcf per year, mainly from southern Alaska). Our analysis indicates that significant sales gas production will not occur until very late in the projection period, as natural gas prices will not be adequate until that time to support the construction of the transportation system necessary to deliver this gas to markets in the Lower- 48 States. Sales of North Slope gas commence between 2005 and 2010 and are projected to be approximately 1 Tcf per year by 2010.

We expect that the utilization of existing LNG import capacity will grow over the projection period, as crude oil and natural gas prices

Table 6-13

Composition of United States Natural Gas Supply

TCF /Year

	1992	1997	2002	2007	2010
Lower-48 States Production	17.5	19.5	20.6	19.6	18.3
Alaska Production	0.2	0.2	0.2	0.3	1.1
LNG Imports	0.1	0.2	0.3	0.3	0.6
Mexican Imports	0.0	0.0	0.0	0.0	0.0
Net Canadian Imports	1.9	2.0	2.0	2.3	2.3
Total Supply / Consumption	**19.7**	**21.9**	**23.1**	**22.5**	**22.3**

Note : The NARG model equilibrates supply and demand at five year intervals.
Estimates for intervening years can be obtained by interpolation.

increase. By the end of the projection period, we anticipate that existing LNG capacity in the U.S., which is in the range of 0.8 to 1.0 Tcf per year, will be extensively utilized. We have not provided for the development of new LNG import capacity and our analysis suggests that this would remain a very marginal option relative to other potential sources of supply over the projection period.

As mentioned earlier, we have not included imports to the U.S. from Mexico in our analysis.

Net imports from Canada are projected to be in the range of 2 Tcf per year in the Control Case over most of the projection period and to contribute approximately 10 percent of the total U.S. supply. Canadian net exports to the U.S. are discussed more fully in section 6.4.4.

As outlined in the previous section, we have compared the results of our analysis to those by AGA, GRI and EIA. Our projection of total supply to the U.S., which corresponds to the total U.S. consumption, is somewhat higher than that of GRI and AGA but corresponds very closely to that of EIA. Our projection of conventional U.S. Lower-48 production is higher than those of the others, but as noted earlier we have not explicitly segregated tight gas from our estimates and this difference is therefore overstated. We also observe that there has recently been considerable success achieved in maintaining and enhancing natural gas deliverability in the U.S. and that there was much more optimism expressed by consultees regarding the outlook for U.S. domestic production than has been evident in the past. This was largely attributed to the future application of recent technological advances and to the optimistic outlook for coalbed methane.

Our projection of unconventional U.S. Lower-48 production is lower than those of GRI and EIA, but higher than that of AGA. If tight gas were segregated in our projection and included in this category then our projection of unconventional gas production would be somewhat higher. In our projection, North Slope production comes onstream somewhat later than in the comparative projections. Our projection of net imports from Canada is very similar to the AGA, GRI and EIA projections during the first half of the projection period and is approximately in the mid-range of these projections thereafter.

To summarize, we have provided an overview of the composition of total U.S. supply in order to provide some perspective on the role that Canadian supply might play in satisfying aggregate North American natural gas demand. Despite the projected growth in Canadian net exports, Canadian gas contributes only about 10 percent of the total U.S. supply over the projection period. The uncertainties inherent in projections of U.S. natural gas demand and the supply available from other sources, particularly the Lower-48 States, implies a range of volumes which is large relative to the projection of total net exports from Canada to the U.S. over the period. This is an important consideration when assessing the potential contribution of Canadian exports to total U.S. supply.

6.4.4 Canadian Exports and Imports

In our analytical framework, two main factors determine the level of Canadian natural gas exports to the United States: the size of the U.S gas market, and the relative delivered costs of Canadian and U.S gas. The analytical framework is useful for making regional projections based on our assumptions about comparative costs, but it is less useful for accurately reflecting certain institutional, commercial and contractual factors which could cause either the overall size of the export market, or the size of flows over particular routes to differ from those in these projections. Where we know about these factors, and where we think that they will be important, we account for them as explained in Section 6.1. Where they are still uncertain, say because the projects to which they may apply are still being developed, we have applied careful judgement in selecting cost assumptions (from often conflicting advice) and we assessed the results for reasonableness, taking into account the range of relative gas and transportation costs which would influence each flow. Nevertheless, there are a number of factors which could cause both the aggregate level of net exports and particularly the regional distribution of exports from Canada to the U.S. to differ from those presented here.

We project Canadian net exports to the United States to increase from about 1.3 Tcf (7 percent of U.S demand) in 1989 to about 1.8Tcf in 1992, 2.0 Tcf in 1997, 2.3 Tcf in 2007 and 2.1 Tcf in 2012 (about 11 percent of U.S demand). A large increase in exports occurs in the near term, as new pipeline capacity to the United States is commissioned (Table 6-14).

Table 6-15 shows a range of other projections of Canadian natural gas exports to the United States which are in the public domain.

Table 6-14

Canadian Natural Gas Trade with the U.S.

(Tcf/Year)

	1989 [a]	1992	1997	2002	2007	2012
Total Gross Flows	1.34	1.84	2.06	2.14	2.60	3.56
of which to:						
Pacific Northwest	0.17	0.20	0.21	0.21	0.22	0.24
California	0.49	0.54	0.55	0.56	0.58	0.70
Central	0.57	0.76	0.80	0.84	1.16	1.64
Northeast	0.11	0.34	0.50	0.53	0.64	0.97
Less ANGTS Re-exports	0.00	0.00	0.00	0.00	0.04	1.18
Gross Canadian Exports	1.34	1.84	2.06	2.14	2.56	2.38
Less Imports to Ontario	0.05	0.02	0.09	0.18	0.22	0.25
Net Canadian Exports	**1.29**	**1.82**	**1.97**	**1.96**	**2.34**	**2.12**

[a] Actual
Note: Totals may not add due to independent rounding.

Most project net exports to reach the 2 Tcf level by the year 2000. Thereafter, projections of exports remain relatively stable in the EMR and EIA studies, but reach as high as 2.4 Tcf in the WEFA study and as low as 1.8 Tcf in the GRI projection by 2010.

Canadian imports from the U.S. may become increasingly important to Ontario within the next 10 years. Imports of gas from the U.S Lower-48 through Sarnia and Windsor could increase from less than 10 Bcf in 1987 to as much as 260 Bcf by 2007. This is apart from the 300 Bcf of Alberta gas re-imported to Ontario via the Great Lakes pipeline. The projected growth in imports to Ontario is very much dependent on relative gas supply and transportation costs. The extent of import growth is uncertain and will depend upon the relative abundance of the resources in Canada and the U.S.

Alaskan gas begins to flow through Canada to the U.S Lower-48 between 2007 and 2012. The ANGTS volumes are roughly 1 Tcf by 2012.

A key finding emerging from this analysis is that, given the assumptions used in our analysis, our competitive position with respect to quantity and cost allows us to maintain a long-term presence in the U.S. market at about 2 Tcf per year, while Canadian natural gas consumption grows over the period at prices consistent with competitive pricing conditions on the North American market.

Given the analytical framework we have used and the input assumptions described earlier, our results provide some insight as to possible changes in the regional distribution of Canadian gas exports, over the projection period, as illustrated in Figure 6-25. We discuss the regional composition of exports up to 2007, beyond which time we cannot distinguish between the Canadian and Alaskan shares of gross flows through each regional export point.

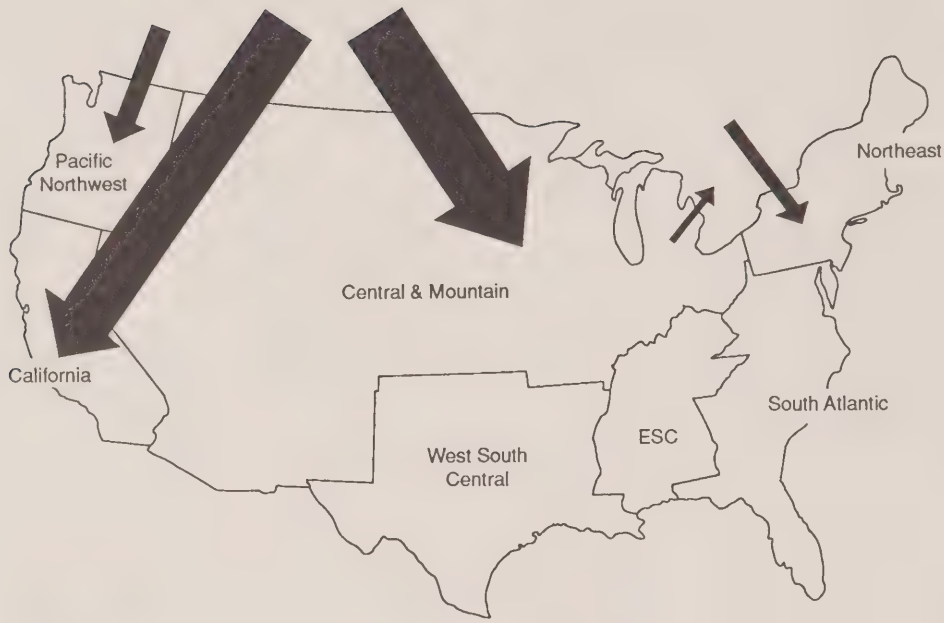
Canada exports natural gas to four main U.S demand centres: the Northeast region, the Central states, California and the Pacific Northwest (PNW) States.

In 1989, Canadian gas exports to the U.S **Northeast** totalled roughly 110 Bcf. Our projections show gas demand in the U.S Northeast growing by over 3 percent per year, mainly due to increasing environmental concerns and strong gas demand in the electricity generation market. The rapidly increasing size of the gas market and favourable supply cost conditions allow Canadian exports to grow to the 500 Bcf range by the end of the 1990s, and the 600 Bcf

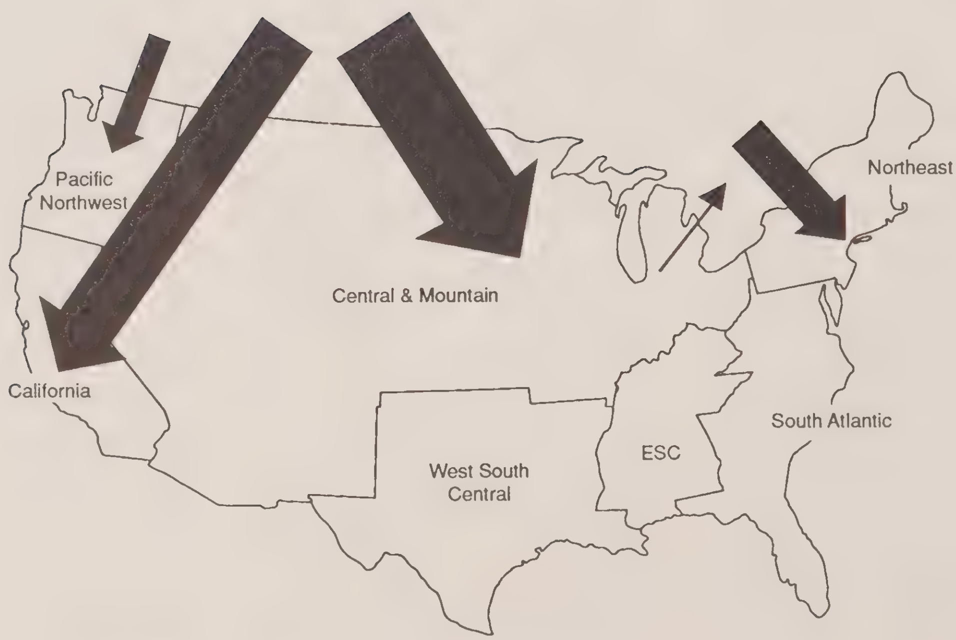
Figure 6-25

Natural Gas
Exports and Imports

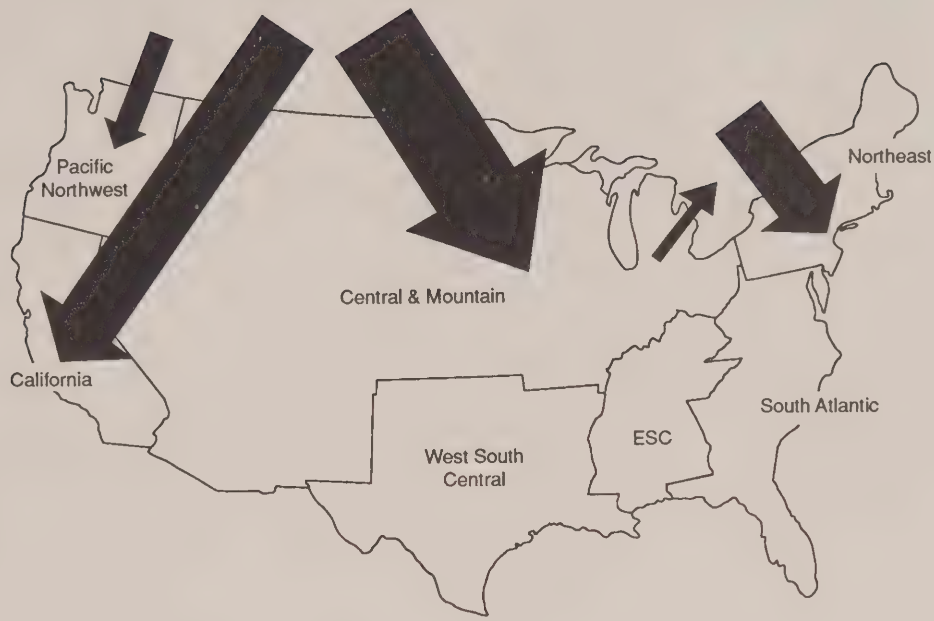
1989



1992



1997


Pacific
Northwest
Northeast
Central & Mountain
California
South Atlantic
ESC
West South
Central

2007


Pacific
Northwest
Northeast
Central & Mountain
California
South Atlantic
ESC
West South
Central

Table 6-15

Natural Gas Exports Range of Views

(Tcf/Year)

	1990[a]	1995	2000	2010
NEB	1.4	1.9	2.0	2.2
EIA		1.7	2.1	2.2
EM&R		n/a	2.1	2.1
GRI		1.8	1.9	1.8
WEFA		1.5[b]	1.8[c]	2.4 [d]

NEB = Control Case, National Energy Board, 1991.

EIA = Energy Information Administration, Annual Outlook for Oil and Gas, 1990.

EM&R = Energy, Mines and Resources Canada, 2020 Vision Canada's Long Term Energy Outlook,1988.

GRI = Gas Research Institute, Baseline Projection of U.S. Energy Supply and Demand to 2010, 1990.

WEFA = The WEFA Group, Regional North American Gas Markets to the Year 2020, Fall 1990

[a] Actual
[b] Average (1991 to 1995)
[c] Average (1996 to 2000)
[d] Average (2006 to 2010)

range by 2007. These exports are delivered over the Iroquois pipeline and an expansion of the Niagara system. Over the longer term, gas exports to the region are anticipated to grow at about the same rate as the region's demand. Canadian pipeline tolls are maintained at the real levels anticipated after the 1991/1992 TCPL expansion; we do not reduce them over time, hence it is mainly relative gas supply costs rather than pipeline tolls which influence this market growth.

The projected growth in Canadian gas exports to the Northeast, despite the long distance from supply to markets, is very much dependent on relative gas supply and transportation costs. A major uncertainty about the extent of export market growth shown for this region is whether U.S. supply will be more abundant and less costly than our assumptions indicate. In these results, Canadian gas is a marginal resource to this market, evidence of which is the variance of projected exports associated with different assumed levels of Canadian gas costs. With stronger competition from U.S. supply, this export market would grow more slowly, reducing the high load factors which our Control Case indicates for TCPL flows from Alberta to Ontario. Lower demand growth in the region would also reduce the export projection.

In 1989, the largest proportion of Canadian gas exports was delivered to the U.S **Central** region. This region consists of the Midwestern and Northwestern states (excluding Washington and Oregon). Exports to the Central region were about 570 Bcf in 1989, representing 44 percent of Canadian gas exports. We project a large increase in the level of Canadian exports to this region, reaching 750 Bcf by the early 1990s, maintaining it as the largest regional destination of Canadian gas exports. The proposed expansion/extension of the Northern Border and Great Lakes pipeline systems would facilitate these increased exports. Thereafter, exports grow more moderately (at about 4 percent per annum), reaching about 1.2 Tcf by 2007. These results indicate a strong competitive position for Canadian gas to this very large region, accessible at moderate transportation cost.

In 1989 **California** was the second largest customer for Canadian natural gas, purchasing approximately 490 bcf (or 24 percent of California end-use gas demand). In that year California sales represented almost 38 percent of total Canadian gas exports to the United States. Heretofore, the principal California market for Canadian gas has been the provision of sales gas to two large distribution companies - Pacific Gas and Electric and Southern California Gas - via their interstate pipeline affiliates PGT and Pacific Interstate, respectively.

The demand for natural gas in California is expected to grow at 2.5 percent per annum over the study period, due primarily to our assumption of stringent environmental controls on the burning of heavy fuel oil in Southern California as well as more moderate but increasingly stringent environmental standards in the northern part of the state. Demand growth across the industrial and electric generation sectors is 3.5 percent per annum on average over the study period.

Currently, the primary competition for Canadian gas in the California market comes from the U.S Southwest (including the San Juan Basin in New Mexico and the Permian Basin in Texas). Coalbed methane from the San Juan Basin is becoming an increasingly important source of supply for California and expansion of the El Paso and Transwestern pipeline systems is being considered. In the near future, Rocky Mountain supplies will comprise an increased share of the supply to the California market. The Kern River pipeline

project is preparing to carry Rocky Mountain gas into the Enhanced Oil Recovery (EOR) projects in Kern County. In sum, Canadian exports face increased competition in the California market from the U.S. Southwest and Rocky Mountain supply regions. Given the increasing diversity of supply sources available to satisfy the projected growth in natural gas demand in California and the relative natural gas supply and transportation costs used in our analysis, the Control Case outlook indicates that Canadian exports to California grow only moderately from 490 Bcf in 1989 to 580 Bcf in 2007.

This result is not consistent with the current proposals for major pipeline expansions between Western Canada and California which are at various stages of development (i.e. the Altamont and PGT Expansion projects). If implemented, either of these projects would add more to export capacity to California than our Control Case projection suggests is required. As in the case of the Northeast export projection, this result occurs largely on account of the relative supply and transportation costs used in our analysis and because we have chosen not to override these results given that neither of these projects at the time of writing is yet certain to proceed. If Rocky Mountain and coalbed methane supplies were more costly or less abundant than we have assumed, or Canadian supply less costly or more abundant than we have assumed, export flows to California would be stronger. In our analysis, small cost differences will influence market share, whereas in reality, various commercial and institutional factors as well as the perception of relative supply and transportation costs and market opportunities held by the project sponsors may be more decisive. This consideration, together with the considerable uncertainty in our analysis about relative gas costs and pipeline tolls, suggests that considerable caution be exercised in interpreting the regional export projections, particularly those to California.

In 1989, Canada exported 170 Bcf to PNW. PNW constitutes a relatively small share of Canadian exports over the outlook period, with relatively modest growth in export volumes projected to occur.

In sum, the main trends which emerge from the Control Case projection of Canadian natural gas exports are that:

1) net exports increase considerably in the near term, to reach about 2 Tcf per year by the late 1990s, and they grow moderately thereafter, peaking in 2007 at 2.3 Tcf; between 2007 and 2012 Alaska supply begins to have a moderating effect on Canadian exports, but Alaska supply is expected to flow to the Lower-48 through Canadian export pipeline capacity, and it is therefore unlikely that Canada would face a situation of underutilized export pipeline capacity;

2) Canada's share of total U.S. gas demand was approximately 7 percent in 1989 and stabilizes in the range of 10 percent over the outlook period;

3) over the 1990s the Central region will account for over one half of Canadian exports, the other half being shared between California and the Northeast; however, a number of factors not explicitly accounted for in our analysis could influence the regional distribution of Canadian exports; and

4) Ontario could become a larger importer of U.S. gas by the end of this decade.

Our Control Case portrays only one of a possible set of outcomes. In particular, this outlook is sensitive to the portrayal of relative gas supply and transportation costs between the United States and Canada. Alternative supply and oil price assumptions do have an impact on the export projections, as discussed in Section 6.5.2. As we have mentioned above, numerous other factors we have not analyzed in detail could affect these results, the regional distribution of Canadian exports being especially sensitive to major departures from certain region-specific gas supply and transportation cost assumptions, and to the effects of certain commercial and institutional factors not explicitly accounted for in our analysis.

6.4.5 Canadian Demand

The Control Case results for Canadian demand are those appearing in Chapter 4.

For convenience, we provide a demand summary for Canada in Table 6-16.

6.4.6 Canadian Supply

Given the overall demand projection, the components of which are summarized in Appendix Table A6-8, we assess sources of supply from established reserves in the WCSB, estimate the timing of start-up of frontier projects on the basis of relationships between prices and costs and project reserves additions from the WCSB.

Table 6-16
Canadian Natural Gas Demand
(Bcf/Year)

	1989	1990	1995	2000	2005	2010
Residential	553	537	581	602	614	629
Commercial	353	348	377	395	414	433
Industrial	894	873	1012	1096	1103	1059
Petrochemicals	163	138	173	186	200	216
Transportation	2	2	6	10	13	17
Total End-Use Demand	**1966**	**1899**	**2150**	**2288**	**2345**	**2355**
Pipeline Fuel and Losses	170	172	201	210	219	215
Electricity Generation	132	97	65	80	105	116
Reprocessing Fuel[a]	13	22	26	28	30	30
Total Primary Demand	**2281**	**2190**	**2442**	**2607**	**2699**	**2715**

Source: See Chapter 4
[a] Excludes reprocessing shrinkage
Note: Totals may not add due to independent rounding.

We begin with a description of productive capacity from established reserves for each region of the WCSB. We follow this with a discussion of reserves additions in the WCSB and the related gas-directed drilling activity. We then describe our projection of productive capacity from these reserves additions in the WCSB. Productive capacity from frontier regions is then discussed, including a description of the methodology used to determine startup dates for frontier projects and the assumptions which were made in developing the projections. We then describe the overall projection of productive capacity, compare it to the 1988 Report cases, and describe the key uncertainties surrounding this projection. Finally, we compare the estimated productive capacity to anticipated demand for Canadian natural gas.

Productive capacity is the term used to describe the estimated natural gas supply capability. *It is the estimated rate at which natural gas can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering and processing facilities, and potential losses due to plant turnarounds and operational problems* (Refer to Inset Box). Productive capacity is distinct from production, which is the volume of natural gas actually produced in order to satisfy demand in any given year.

We derived our projections of productive capacity for non-associated gas pools using a modelling framework which takes account of each gas pool's well flow characteristics, basic reservoir parameters and daily contract rate. This approach also incorporates drilling and compression cost data and projected producer netbacks to assess the economics of adding infill wells and/or field compression to maintain productive capacity at or near the established contract rate.

6.4.6.1 Productive Capacity from Established Reserves in WCSB

In developing our projections of productive capacity from established reserves, we examined two distinct categories of reserves - producing and non-producing. Producing reserves are those in gas pools with commercial production reported by the respective provincial agencies. This category may include some gas pools which in the past have had significant test production, but may in fact not be currently producing; however, we do not believe this to be a significant factor influencing our projections. All other reserves are included in the non-producing category.

We examine productive capacity from producing reserves and non-producing reserves separately because the contractual arrangements for pools currently on production are anticipated to differ from those not yet being produced and it is therefore appropriate to apply different assumptions to each category in order to develop representative projections of productive capacity. Different assumptions also apply to each producing region. Those assumptions are outlined in the discussion which follows.

In the following discussion, all estimates of reserves are remaining marketable established reserves as of year-end 1989.

Producing Established Reserves

Based upon information from the

Productive Capacity

***Productive capacity** is the estimated rate at which natural gas can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering and processing facilities, and potential losses due to plant turnarounds and operational problems.*

The maximum annual productive capacity is therefore derived on the basis that all pools would be produced at their capability every day of the year, restricted for the most part by reservoir capability and field gathering and processing facilities and with only a small adjustment (approximately 5-7 percent) for operational unreliability. The adjustment for operational unreliability is to account for the fact that there will be downtime for both wells and production facilities. The productive capacity projections represent total field capability to deliver marketable gas and are not restricted by either provincial gathering or mainline pipeline capacity.

In making our comparisons of supply and demand, we illustrate supply and demand scenarios in which certain levels of reserves additions are derived so as to ensure that production and demand are in balance over the longer term. However, we do not believe that equating productive capacity, as opposed to production, to demand is a realistic representation of the functioning of natural gas markets in the longer term.

To clarify the above point, demand projections represent average annual demand and are not intended to reflect peak day demand. Demand on any given day could be as much as 50 percent higher than the average day over the year. Storage facilities are one method used to cope with this variability between peak and average day. Storage facilities, usually close to the marketplace, are filled during periods of low demand (summer load) and are drawn down during peak demand periods (winter load). The impact of storage is such that peak pipeline throughputs, and therefore peak production rates, tend to be some 25 percent higher than average rates. The variability in production is therefore somewhat less than in end use demand.

There are other factors which have the effect of maintaining productive capacity at a level higher than the annual average production rate. Specific contractual arrangements have the effect of reducing the extent to which there can be a "perfect matching" of productive capacity and demand. There are contractual links which tie specific supply sources to specific markets, as well as necessitating the use of particular transportation systems.

It is for these reasons that gas supply contracts have generally been formulated so as to provide both producers and purchasers a degree of flexibility by specifying load factors requiring peak day capability ranging between 100 and 133 percent of average day. It is unlikely that sufficient storage will be available, particularly as demand increases, to keep all pipelines running at 100 percent load factor. Even if this were possible, it is unlikely that contractual practices will dramatically change such that producers will not be required to maintain an excess of productive capacity over the anticipated average annual production rate. It would not appear to be reasonable to expect that all pools would coincidentally produce at their maximum capability on a continuous basis.

We therefore conclude that in order for production to be equal to demand, productive capacity, represented by the sum of average annual capability at the pool level, will have to exceed average annual demand. We estimate that as gas markets tighten up over the projection period, productive capacity in aggregate would have to be maintained at a level some 10 to 15 percent higher than average annual production in order to satisfy demand.

This approach is somewhat different from that which we have used in the past, and adjustments have been made to the historical productive capacity estimates to make them consistent with our current projections.

British Columbia Ministry of Energy, Mines and Petroleum Resources, producing gas pools in **British Columbia** have been categorized as either non-associated (established reserves of 5.8 EJ) or associated and solution (established reserves of 0.2 EJ).

Our projections of productive capacity for some 440 non-associated gas pools in British Columbia were derived using the modelling framework discussed earlier, assuming an initial rate of take of 1:5000 (see Inset Box). Current rates of take in B.C. range from 1:3500 to 1:5500. On the basis of our consultations, we consider an overall rate of take of 1:5000 at the pool level to be representative of that which can be anticipated over the projection period.

Our estimate of current productive capacity from non-associated gas reserves in B.C. is some 538 PJ per year; productive capacity is expected to decline steadily over the projection period to a level of some 25 PJ per year by the year 2010.

The associated and solution gas projection is based, in part, on our oil production projection for B.C. In aggregate, we expect that the level of solution gas and associated gas production will remain relatively constant over the study period, at a level of approximately 13 PJ per year.

Our overall projection of productive capacity from producing established reserves in B.C. declines from a current level of some 550 PJ per year to less than 40 PJ per year by the end of the projection period. These projections of productive capacity from producing reserves in British Columbia are shown in Appendix Table A6-9.

We examined the producing characteristics of four categories of producing gas reserves in **Alberta** - non-associated gas (established reserves of 25.5 EJ), southeastern Alberta shallow gas (established reserves of 5.6 EJ), solution gas (established reserves of 4.3 EJ) and associated gas reserves and gas reserves in cycling pools (established reserves of 7.9 EJ). The last category includes Alberta's deferred reserves.

Our projections of productive capacity for over 5400 non-associated gas pools were derived using the modelling framework described earlier. A detailed examination of some 150 of the most productive of these 5400 pools was conducted and included input from the operators of most of the pools. We derived our projections of productive capacity from all of the non-associated pools assuming that 65 percent would be produced at the 1:7000 rate of take representative of historical long-term contracting practices, and 35 percent at a 1:3500 rate of take characteristic of many contracts entered into since the late 1970s. While there was some divergence of opinion during our industry consultations, it was suggested by most consultees that overall rates of take should be in the range of 1:5500. The methodology we have used suggests an overall rate of take of about 1:5800 and results in a total estimate of Alberta productive capacity in 1990 that is generally consistent with industry views provided during our consultation process.

The current productive capacity of non-associated gas pools is estimated to be some 2900 PJ per year and is expected to decline over the study period to some 170 PJ by the year 2010.

We derived our productive capacity projections for the Milk River/Medicine Hat/Second White Specks shallow gas reserves in southeast Alberta by field using a production decline analysis approach. We projected the infill drilling required to fully develop the fields and in this context maintained a constant level of production for as long as possible. Some small pockets of these shallow gas

Rate of Take

Rate of take refers to the initial rate at which gas will be produced from an entity such as a well, pool, field or area. It is usually expressed as a ratio. For example, a rate of take of 1:7000 means that 1 unit of production on a daily basis is obtained for each 7000 units of reserves for the entity under consideration.

Rates of take vary considerably, as a function of such factors as geographic location, pool size, reservoir quality, economics and contractual considerations. We have selected rates of take for the various categories of reserves after taking into consideration views received during our industry consultations.

reserves are not yet producing, but since their contribution is minor relative to the overall shallow gas productive capacity, we made the assumption that they are now all producing. We project the productive capacity of the shallow gas pools of southeast Alberta to decline from some 410 PJ per year to 80 PJ per year by the year 2010.

We based our projection of solution gas productive capacity on our projection of the productive capacity for the relevant oil pools and a projection of gas to oil ratios in those pools. We expect that the current level of productive capacity of 437 PJ per year will decline to a level of 50 PJ per year by the end of the study period.

We examined some 22 major cycling pools in Alberta and acquired considerable input from the operators and the ERCB for our analysis. Productive capacity from these pools is expected to peak in 1991 at a level of some 428 PJ per year and decline thereafter to a level of some 49 PJ in 2010. Production from miscellaneous associated gas pools is currently about 85 PJ per year. We expect that this level of associated gas production will remain fairly constant as various gas caps commence blowdown over the projection period.

In aggregate, the productive capacity from producing reserves in Alberta is currently estimated at some 4200 PJ per year, and is expected to decline to less than 150 PJ per year by the end of the study period.

Our projections of productive capacity from producing reserves in Alberta are shown in Appendix Table A6-9.

Our examination of productive capacity from producing reserves in **Saskatchewan** comprised three categories: shallow formations similar to southeastern Alberta (established reserves of 0.9 EJ), non-associated pools (established reserves of 1.0 EJ), and associated and solution gas pools (established reserves of less than 0.2 EJ).

Our projections of productive capacity from the shallow Milk River/Medicine Hat formations were derived using the production decline methodology described above for southeast Alberta and are based on comprehensive data for specific reserves analyzed in the context of recent export applications. Our projection of productive capacity for these shallow formations peaks at some 111 PJ in 1991 and declines thereafter to essentially zero by the end of the projection period. Our current overall estimates of reserves for these shallow formations may be somewhat understated and are currently under review.

Productive capacity from defined[1] non-associated gas pools was derived assuming an initial rate of take of 1:5000. Productive capacity for the miscellaneous undefined producing gas pools was projected to decline in proportion to the defined pool profile. In total, current productive capacity from these producing non-associated gas reserves is estimated to be some 93 PJ per year, declining to 3 PJ per year by 2010.

We based our projection of associated and solution gas productive capacity on our projection of the productive capacity for the relevant oil pools and a projection of gas to oil ratios in those pools. We expect that the current level of productive capacity of some 16 PJ per year will decline to about 1 PJ per year by the end of the study period. In our analysis, we did not project any significant blowdowns from gas caps before 1995.

In aggregate, the productive capacity from producing reserves in Saskatchewan is expected to decline throughout the projection period from a current level of over 217 PJ per year to some 5 PJ per year by the end of the study period.

Our projections of productive capacity from producing reserves in Saskatchewan are shown in Appendix Table A6-9.

In addition to B.C., Alberta and Saskatchewan, **other producing areas** contribute to the overall productive capacity projection for producing reserves. We projected productive capacity for the Kotaneelee field in the southern Yukon and the Pointed Mountain field in the southern Northwest Territories on an individual pool basis. Our estimates of productive capacity for Ontario (and Quebec, which has very minor production) are based on historical trends. Our projections of productive capacity from producing reserves in these other producing areas are shown in Appendix Table A6-9.

Non-Producing Established Reserves

In developing our projection of productive capacity from non-producing established reserves, there were two important consider-

1 **Defined** pools are specific pools identified by the Saskatchewan Department of Energy and Mines in named fields, whereas **undefined** pools are those pools grouped by Saskatchewan Energy and Mines into a "Miscellaneous" category.

ations: the rate at which these pools will be connected and the initial rate of take at which they will be produced.

The large number of non-producing gas pools (close to 11 000 in Alberta and 400 in B.C.) and the difficulty in examining the location of these pools in relation to existing or proposed pipeline facilities dictated that we adopt a generalized approach to projecting connection rates for these pools. We expect that non-producing reserves will be connected over a period of time in a phased manner taking account of the industry's ability to physically connect new sources of supply, the time required to acquire firm transportation service and the likelihood that some reserves will require a longer period of time to become economic to connect. Based on our industry consultations, we determined that a schedule of connection rates of 5, 15, 20, 20, 15, 15, 5, 2, 2, and 1 percent per year would be reasonable. We recognize that changing market conditions could cause this to occur somewhat faster or slower than projected. This connection schedule for non-producing pools also assumes that those pools currently uneconomic due to size and/or distance from existing facilities would become economic within ten years.

We anticipate that future contracting practices will differ somewhat from those which have been observed in the past. In particular, we expect that currently non-producing pools will be produced at somewhat faster initial rates of take, on average, than pools which are currently on production, although this will be tempered to some extent by the need for long term contractual arrangements in certain instances. Initial rates of take were selected so as to reflect a change in contractual practices and differ for the various producing regions.

Productive capacity estimates for some 371 non-producing gas pools containing 2.2 EJ of reserves in **British Columbia** were derived using our modelling framework assuming an initial rate of take of 1:4750. (Input received during our consultations suggested that initial rates of take for non-producing reserves should range from 1:4500 to 1:5000.) Applying our schedule of non-producing connection rates to this productive capacity profile results in a peak productive capacity of some 150 PJ per year in the year 1997, declining thereafter to some 30 PJ per year by 2010.

In **Alberta** there are some 19.9 EJ of non-producing non-associated gas reserves. At year-end 1988, some 13.6 EJ of those reserves were identified in 10 638 gas pools, and productive capacity projections were derived using our deliverability model for those pools. While there was a large divergence of opinion regarding initial rates of take, ranging anywhere from 1:2000 to 1:7000, we concluded after our consultations that it would be reasonable to assume that initial rates of take for non-producing Alberta reserves should reflect pool size, with smaller pools producing at the highest initial rate of take. In many cases smaller pools, especially single-well pools, are now being connected and produced at initial rates of take as fast as 1:2000. Larger pools can be produced more economically at slower rates of take and generally tend to be produced in that manner.

The rates of take we assumed for non-producing non-associated Alberta reserves were:

- 1:5250 for some 5.4 EJ of reserves in 617 pools with initial reserves of 100 million cubic metres (4 PJ) or more;
- 1:4125 for some 4.6 EJ of reserves in 2387 pools with initial reserves between 30 and 99 million cubic metres (1 and 4 PJ); and
- 1:3000 for some 3.5 EJ of reserves in 7634 pools with initial reserves less than 30 million cubic metres (1 PJ).

We have no reason to believe that the additional 6.3 EJ of non-producing reserves, added during 1989, would have different producing characteristics than the 13.6 EJ examined in detail. After applying the connection rates described earlier, non-producing gas reserves in Alberta are estimated to be capable of producing some 1500 PJ per year by 1998, declining thereafter to less than 200 PJ per year in 2010.

Productive capacity from the estimated 0.4 EJ of non-producing non-associated gas reserves in **Saskatchewan** was based on our productive capacity projections for producing non-associated gas reserves. Applying the connection rates discussed above, non-producing reserves in Saskatchewan are expected to be capable of some 30 PJ per year of production by 1999, declining thereafter to less than 10 PJ per year by 2010.

Our projections of productive capacity from non-producing reserves in British Columbia, Alberta and Saskatchewan are summarized in Appendix Table A6-9.

Summary of Productive Capacity from Established Reserves

In aggregate, productive capacity from established reserves in British Columbia is expected to increase from a current level of some 550 PJ per year to a peak of almost 600 PJ per year in 1994 and decline thereafter to less than 100 PJ per year in 2010.

In Alberta, current productive capacity from established reserves of some 4300 PJ per year is expected to decline gradually throughout the study period to about 600 PJ per year in 2010.

Productive capacity from established reserves in Saskatchewan is expected to decline steadily over the study period from a peak of over 200 PJ per year in 1991 to some 10 PJ per year in 2010.

In the other producing regions productive capacity is also expected to decline from a peak of some 41 PJ per year in 1991 to about 6 PJ per year in 2010.

In aggregate then, productive capacity from established reserves in the conventional producing regions of Canada is expected to remain relatively constant over the first five years of the projection, but to decline overall from a level of over 5100 PJ per year currently to about 750 PJ per year in 2010.

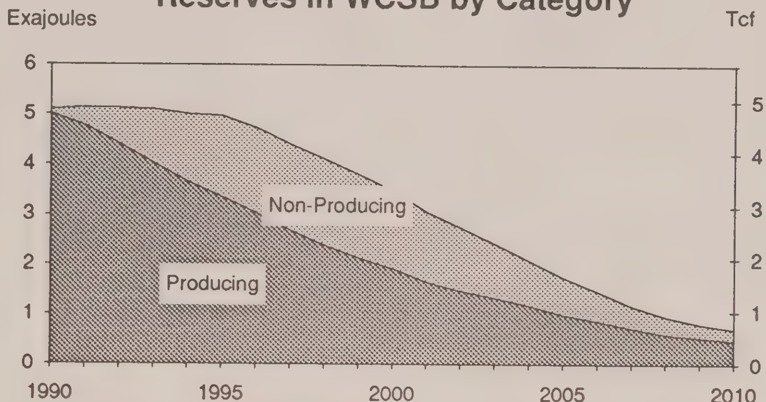
These productive capacity projections for established reserves yield R/P ratios declining over the first eight years of the study period from the current level of 14.6 years to about 8 years and remaining relatively constant thereafter.

Our projections of productive capacity from established reserves in the WCSB are summarized in Appendix Table A6-9. Figures 6-26 and 6-27 illustrate productive capacity from established reserves in the WCSB. Figure 6-26 shows the levels of productive capacity from producing and non-producing reserves, and Figure 6-27 shows the levels of productive capacity from each producing region.

There are a number of uncertainties related to our projection of productive capacity from established reserves; because productive capacity is not measured, even the current level of productive capacity is estimated. Among the uncertainties related to these projections are the following:

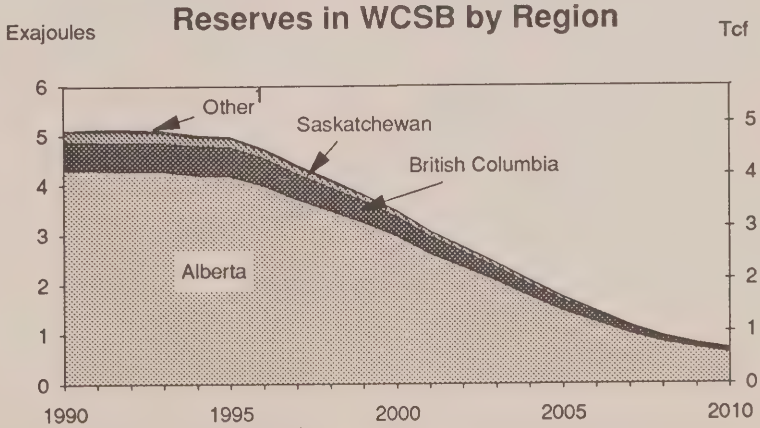
- the projections are heavily dependent on estimates of established reserves, which are in themselves uncertain because, over time, reserves estimates in a given pool may increase or decrease as the

Figure 6-26
Productive Capacity from Established Reserves in WCSB by Category



Includes productive capacity in Ontario.

Figure 6-27
Productive Capacity from Established Reserves in WCSB by Region



1. "Other" includes Ontario.

pool is developed and production from the pool more clearly indicates the level of established reserves;

- future trends in contractual practices and the specific rates of take on a regional basis cannot be known with certainty;

- reliable deliverability data is often not available for non-producing reserves, and the economic viability of a portion of this category of reserves is questionable;

- while generalized assumptions about the industry's ability to connect new reserves can be made, it is not possible to predict with certainty the level of new reserves to be connected over time; and finally

- the timing and level of associated gas production is highly dependent upon our oil production projections which in themselves have inherent uncertainties.

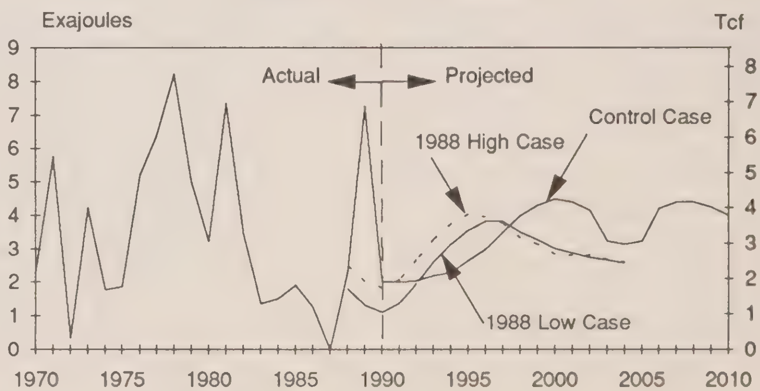
6.4.6.2 Reserves Additions in the WCSB

As productive capacity from established reserves declines over the projection period, it will increasingly become necessary to rely on productive capacity from reserves additions in the WCSB, along with productive capacity from the frontier regions, to meet the increasing levels of domestic and export demand. Our projection of reserves additions is based on the natural gas price path and direct costs for the WCSB described earlier in this chapter. Reserves additions are projected so as to maintain productive capacity over the longer term at a level some 10 to 15 percent higher than average annual production, or demand (refer to the inset box in section 6.4.6 for a more detailed description of our approach to estimation of productive capacity).

Reserves additions are projected to remain relatively flat in the near term at about 2.0 exajoules per year. Reserves additions begin to increase in the period beyond 1995 with growth in natural gas demand and prices and as the current excess of productive capacity in the WCSB begins to diminish. We have assumed that the producing sector in Western Canada would moderate its activity somewhat in advance of the onstream dates of significant new supply sources in the frontier regions. In anticipation of Mackenzie Delta production startup, reserves additions in the WCSB are therefore projected to decline somewhat in the early 2000s. Were this not to occur, and given our demand projection, there would be a greater surplus of productive capacity relative to demand and more downward pressure on prices than we have projected over this period. Over the latter portion of the study period, additions exhibit renewed growth as demand further increases and supply from established reserves continues to decline (Figure 6-28).

Over the period from 1970 to 1989 reserves additions have averaged 3.5 exajoules per year (Appendix Table A6-10). A total of 72 exajoules of natural gas from the WCSB, or an average of 3.4 exajoules per year, is projected to be added over the period 1990 to 2010 in the Control Case (Appendix Table A6-10). These additions represent 69 percent of the undiscovered recoverable resource estimate for the WCSB of 105 exajoules in the Control Case and about 46 percent of the estimate of 155 exajoules in the high resource sensitivity case. However, it would clearly not be possible to sustain these levels of

Figure 6-28
Marketable Natural Gas Reserves Additions in WCSB



additions from the WCSB in the low resource sensitivity case where the undiscovered recoverable resource estimate is only 55 exajoules.

Our projection of reserves additions is intended to be indicative of the overall trend in annual additions and of the cumulative additions from the basin over the study period necessary to achieve the projected levels of productive capacity. Actual reserves additions will depend on many factors, including natural gas prices and demand, finding rates and costs and activity levels and, as the historical data suggests, will be much more variable on an annual basis than our analysis suggests.

In the 1988 Report our projection of reserves additions averaged 2.4 exajoules per year in the low case and 2.7 exajoules per year in the high case over the period 1987 to 2005. Over this period of 19 years, we projected reserves additions of 51 and 56 exajoules in the low and high cases, respectively, representing 57 and 63 percent of our estimate of undiscovered recoverable resource potential at that time. The higher estimates of reserves additions in the Control Case reflect our revised assessment of resource potential and direct costs for the WCSB and the increase in demand for Canadian natural gas projected in this study as compared to the 1988 Report.

6.4.6.3 Projected Gas-Directed Drilling Activity in the WCSB

To broadly assess the reasonableness of our projected reserves additions over the study period, we estimate exploratory drilling levels necessary to achieve the required reserves additions.

It is not possible to determine if an individual well was drilled with the intent of finding natural gas or crude oil. Accordingly, for historical data we use actual drilling results as a proxy for drilling intent. Wells which discovered natural gas are classified as gas-directed, whereas those which found crude oil are classified as oil-directed. The abandoned wells in each year are assigned to one of these categories in the same ratio as the successful wells. (Our projection of oil-directed activity is discussed in section 7.2.1.4.)

As described earlier in this chapter, we expect a progressive decline in reserves additions of natural gas per metre of exploratory drilling over the projection period, with the rate of decline being related in part to our estimate of the size of the undiscovered resource. For each projected annual reserves addition, we estimate the required annual gas-directed exploratory drilling on the basis of the reserves additions rate trend shown earlier in Figure 6-5. The gas-directed exploratory drilling in the WCSB required to achieve the reserves additions discussed above is illustrated in Figure 6-29.

To achieve the projected reserves additions, gas-directed drilling activity would have to increase over the study period, from an estimated level of about 1.7 million metres in 1990 to a peak of 4.9 million metres in the year 2009. As discussed earlier, a modest downturn in activity occurs between the years 2001 and 2006 and again after 2009 as we anticipate that the industry would react to plans to commence production of natural gas from the Mackenzie Delta around the year 2004 and to increase Mackenzie Delta production near the end of the projection period by tempering somewhat the activity level in the WCSB.

Figure 6-29 compares the projection of gas-directed drilling activity in the Control Case with the high

Figure 6-29
Gas-Directed Exploratory Drilling in WCSB

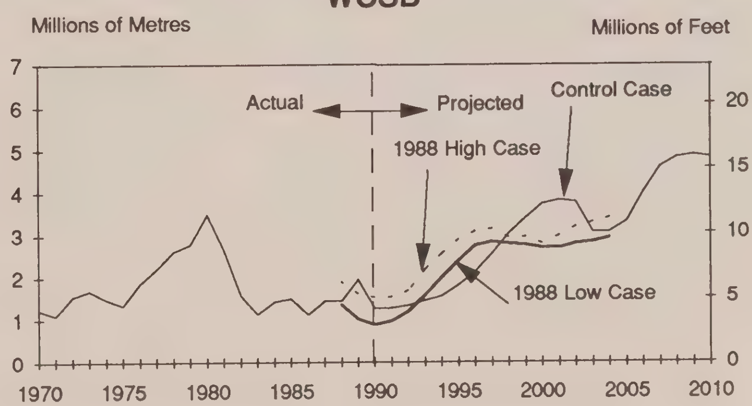
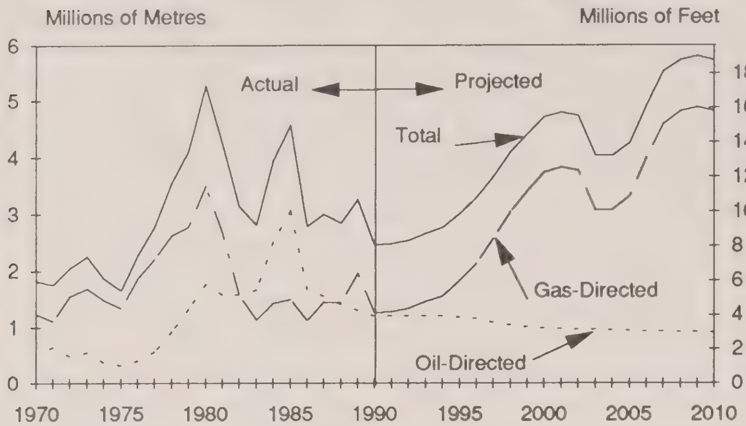


Figure 6-30
Division of Exploratory Drilling in WCSB



and low cases from the 1988 Report. The differences between our current projections and those of the 1988 Report are due, in part, to our revised assessment of the size and cost of the WCSB natural gas resource and to revisions to our estimate of productive capacity from established reserves. More importantly however, our projection of gas-directed activity is higher than our estimates in the 1988 Report in the longer term due to a much higher level of demand in our Control Case as compared to the cases in our previous report.

We obtain estimates of total exploratory drilling for each year of the projection period by summing the individual estimates for gas-directed and oil-directed activities. The results of this analysis are shown in Figure 6-30. Total exploratory drilling increases from 1990 levels of about 2.5 million metres to between 5 and 6 million metres per year by the end of the projection period. Natural gas-directed drilling activity comprises an increasing proportion of the total drilling activity as oil-directed activity remains relatively stable.

Beyond about the year 2000, the projected levels of exploratory drilling approximate and then exceed the peak levels observed in the recent past. During 1990, rig activity reached a maximum of about 300 rigs active out of an available fleet of approximately 500. Given increased utilization of the existing rig fleet and sufficient lead time to expand the available fleet, we anticipate that the sustained level of activity projected over the latter part of the study period could be reasonably achieved by the industry. Moreover our projected price path incorporates a rate of return sufficient to induce the necessary investment.

It is important to recognize, however, that this projection is intended to indicate general trends in activity over the study period and that there is uncertainty regarding a number of the assumptions used to derive the projection. The estimated gas-directed drilling activity is particularly dependent upon the reserves additions rate trend described earlier in this chapter. With the exception of our recognition of some decline in activity prior to commencement of production from the Mackenzie Delta, we make no attempt to project year-to-year fluctuations in drilling activity. We also recognize that there are various plausible combinations of finding rates and activity levels which could result in the reserves additions projection of our Control Case.

6.4.6.4 Productive Capacity from Reserves Additions in the WCSB

To project productive capacity from reserves additions in the Control Case, we have assumed that future additions will have producing characteristics similar to those which we have assumed for established non-producing reserves (refer to section 6.4.6.1). We used three connection rate profiles for reserves additions, based on projected natural gas prices and the excess of productive capacity over demand. Reserves additions were connected over 10, 6 and 4 years (see Appendix Table A6-11), with the connection rate accelerating as natural gas prices increase and the excess of supply diminishes. If we had used a more uniform connection schedule over time, the surplus of productive capacity relative to demand would be higher than we have projected during the early years of the projection.

Productive capacity from reserves additions in the WCSB grows throughout the projection period, reaching 1.8 exajoules (25 percent of total productive capacity) by 2000, 2.7 exajoules (50 percent)

by 2003 and almost 4.0 exajoules (70 percent) by the end of the study period (see Appendix Table A6-13).

Tight gas contributes only very modestly to productive capacity over the latter portion of the study period.

6.4.6.5 Productive Capacity from Frontier Regions

We schedule the startup of frontier projects, namely the Mackenzie Delta/Beaufort Sea and the East Coast Offshore, based on the relationship between the estimated supply costs for the regions discussed earlier in this chapter and the natural gas price path. The methodology for scheduling startup of major projects is discussed more fully in section 7.2.1.2.

Based on data examined during the NEB's 1989 hearing on gas exports from the Mackenzie Delta[1], we expect that sufficient productive capacity will be available from established reserves to initially support a pipeline capacity of some 485 PJ per year. Production is projected to commence in 2004.

This timing is coincident with our projected startup of Amauligak oil production discussed in section 7.3.1.2. While this timing would facilitate the construction of a combined natural gas liquids and crude oil pipeline, it could lead to logistical difficulties in constructing concurrently both a natural gas and a crude oil pipeline. In order to avoid these difficulties it may be necessary to stagger the oil and gas development. In the event that natural gas development preceded oil development, the construction of a liquids pipeline would be required. Advancement of construction of the liquids pipeline between the Mackenzie Delta and the existing small diameter pipeline from Zama Lake to Norman Wells would appear to be a possible option to enable pentanes plus and other liquids associated with the gas production to be transported to markets prior to commencement of oil production from Amauligak.

Given estimates of future reserves additions potential in the Mackenzie Delta area and technical data on the fields to be initially connected, we anticipate that supply will be available to allow pipeline capacity to be increased to a level of 800 PJ per year through the installation of compression. We project that this would occur about 5 years after initial startup, or in approximately 2009.

We project that the East Coast Venture project would commence gas production by the year 2010 at a level of some 125 PJ per year.

6.4.6.6 Total Productive Capacity

Total natural gas productive capacity (unadjusted for carry-forward) is projected to remain relatively stable over the projection period, increasing from some 5.1 exajoules per year to about 5.5 exajoules per year by 2004 when frontier production commences, declining slightly thereafter until incremental frontier supplies are added in 2009 and increasing to 5.6 exajoules per year by 2010 (Appendix Table A6-13). Productive capacity from reserves additions becomes

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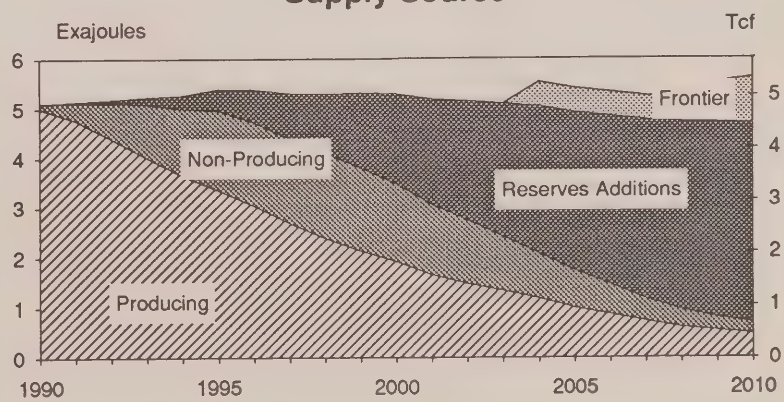
1 A hearing (GH-10-88) held during 1989 in the matter of applications by Esso Resources Canada Limited, Shell Canada Limited and Gulf Canada Resources Limited pursuant to Part VI of the NEB Act for licences to export natural gas.

Figure 6-31
Productive Capacity of Natural Gas by Supply Source



increasingly important, surpassing the productive capacity from established reserves in the WCSB by the year 2003 (Figure 6-31).

Figure 6-32 compares our projection of total productive capacity for the Control Case to the high and low cases from the 1988 Report. The Control Case projection is higher than either of the two 1988 Report cases; the difference is attributable both to modifications to our supply analysis (productive capacity from established reserves and the size, cost and producing characteristics of the undiscovered resource) and to the higher projection of demand in this study.

In section 6.4.6.4, we noted that there are many uncertainties in our projection of productive capacity from established reserves. There is perhaps greater uncertainty in regard to the projections of productive capacity from reserves additions in the WCSB and from the frontier regions. These uncertainties, among them the size, cost and producing characteristics of the undiscovered resource in Western Canada, the impact of technological change on costs, the possible role of unconventional natural gas resources, the timing and scope of frontier projects, and future reserves additions rate trend have been discussed throughout this chapter.

Figure 6-32
Productive Capacity of Natural Gas
Comparison of Control Case with 1988 Report

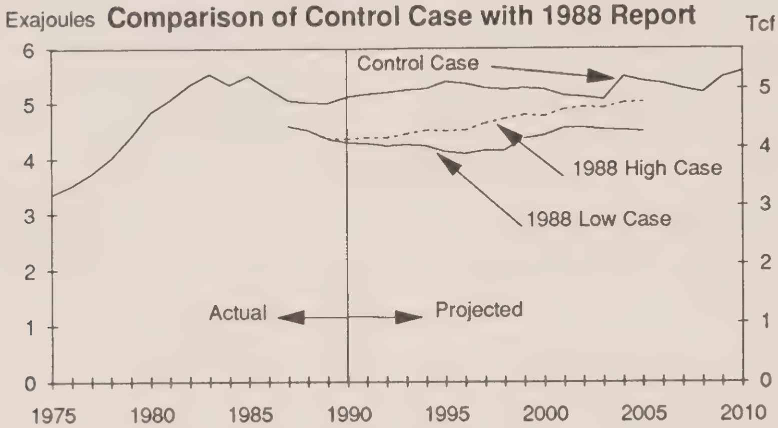
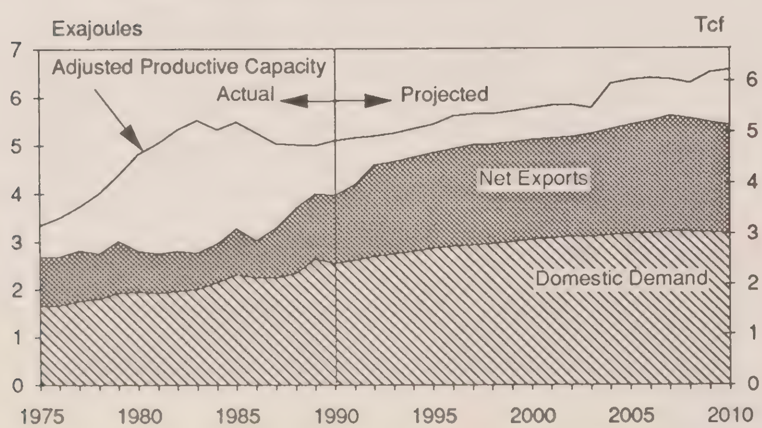


Figure 6-33
Natural Gas Supply and Demand



6.4.6.7 Natural Gas Supply/Demand Relationship

Our comparison of supply and demand over the past 20 years and our projections of supply and demand for the Control Case is illustrated in Figure 6-33 (also refer to Appendix Tables A6-12 and A6-13). The productive capacity shown in Figure 6-33 has been adjusted to reflect production at total demand levels. As outlined earlier, we anticipate that it will be necessary to maintain productive capacity at a level exceeding annual production in order that production be adequate to meet the seasonal pattern of projected demand.

Including frontier supply, total adjusted productive capacity is projected to increase from the current level of 5.1 exajoules per year to approximately 6.4 exajoules per year by 2006, decline slightly to 2008 and increase to 6.6 exajoules per year by 2010 due to incremental frontier production. Total production is equivalent to demand and grows from about 4.0 exajoules in 1990 to approximately 5.5 exajoules by the end of the projection period.

Production from the WCSB is projected to increase from the current level of 4.0 exajoules per year to about 5.6 exajoules per year by the year 2008 and to

decline thereafter. Remaining reserves for the WCSB are projected to decline over the projection period, from a level of 74 exajoules at year-end 1989 to some 42 exajoules at year-end 2010. Corresponding reserves to production ratios (R/P ratios) for the WCSB are projected to decline from the current level of 18 to about 10 by the year 2000 and to remain relatively constant thereafter (Appendix Table A6-14).

A number of observations can be made about our supply outlook for natural gas:

- the surplus of productive capacity relative to demand is projected to narrow over the projection period, but particularly in the near term the excess supply is likely to continue to place downward pressure on price, perhaps to a greater extent than accounted for in our projections;

- reliance on reserves additions in the WCSB and on supply from the frontier regions will increase substantially over the study period;

- while the level of drilling activity required to achieve these reserves additions is difficult to project, our analysis suggests that a considerable increase in activity will be necessary, particularly over the latter portion of the projection period;

- production continues to be supplied primarily from Alberta, but we anticipate growth in the contribution of supply from B.C. (to about 15 percent of total production by the end of the projection period); we foresee no appreciable change in Saskatchewan's share of total production;

- our overall supply projection includes a modest contribution from tight gas, but does not include any contribution from coalbed methane; to the extent that coalbed methane became viable over the projection period it would reduce the need for conventional reserves additions in the WCSB and for frontier supply, or alternatively provide scope for increased production as compared to the Control Case;

- a higher estimate of undiscovered resources in the WCSB could temper the projected decline in the reserves additions rate trend and reduce activity levels relative to those we have projected, providing the potential for increased levels of exports over the longer term from the WCSB; alternatively, if the resource were smaller than we have projected in the Control Case, there would be increased reliance on frontier supply to meet the projected demand level or, perhaps more likely, lower production of Canadian gas than our analysis indicates.

Finally, we emphasize that there are many uncertainties related to this projection, a number of which have been highlighted in preceding sections of this chapter. Our projections are intended to provide an indication of the outlook for domestic natural gas supply over the longer term given what we consider to be a plausible range of assumptions. We do not attempt to project the short-term variability in reserves additions and activity levels which will inevitably occur and to which the upstream industry and the market generally will need to adjust.

6.5 Sensitivity Cases Results

6.5.1 High and Low Oil Price Sensitivity Tests

High Oil Price Sensitivity Test

As explained in Section 6.3, the purpose of this sensitivity test is to examine the impact of higher oil prices on natural gas prices, demand, supply and international trade. Our expectation is that higher oil prices would stimulate demand for and supply of natural gas, cause natural gas prices to increase relative to Control Case prices, (but not necessarily in proportion to the increase of oil prices), and cause Canada's gas exports to increase. Higher oil prices should also strengthen gas flows on the TCPL system and accelerate the viability of Northern gas development for Southern markets. All of these expectations are confirmed in the results of our analyses, as shown in Table 6-17.

The major observations arising from Table 6-17 are that:

1) the impact of the higher oil price on natural gas prices is noticeable, (but small) by 1997, but hardly matters to overall demand and flows till several years thereafter;

2) by 2012, the impact of high oil prices on North American natural gas consumption is quite large, representing a change of about 2.5 Tcf per year, or about 10 percent above Control Case levels;

3) the impact on TCPL flows to Ontario becomes large after the turn of the century - by 2012 representing about a

Table 6-17

Selected Results Comparison: Control Case vs High Oil Price Case

	1997	2002	2012
Alberta Fieldgate Price[a]			
Control	2.35	3.04	4.24
High Oil Price	2.53	3.26	4.65
North American End Use Demand[b]			
Control	22.3	23.5	22.5
High Oil Price	22.6	24.6	25.0
Net Canadian Exports[b][c]			
Control	2.0	2.0	2.1
High Oil Price	2.0	2.2	2.1
TCPL Flows to Ontario[b]			
Control	1.5	1.4	1.5
High Oil Price	1.6	1.6	1.9
MacKenzie Delta Flows[b]			
Control	n/a	0.1	0.7
High Oil Price	n/a	0.4	0.7
ANGTS Flows[b]			
Control	n/a	n/a	1.2
High Oil Price	n/a	0.2	2.1

[a] $1990 Canadian/GJ
[b] Tcf per year
[c] Derived as explained in Section 6.4.1.4

35 percent increase relative to the Control Case;

4) the Mackenzie Delta project shows larger flows earlier in time with high oil prices; we have constrained the eventual size of these flows to 0.7 Tcf per year based on pipeline capacity and supply considerations;

5) in 2007, before ANGTS becomes competitive, Canadian net exports in the high oil price case exceed Control Case exports by about 10 percent. By 2012, there is almost a doubling of the ANGTS flows between the high oil price and Control Cases, causing Canada's net exports to be no higher in the high versus the control oil price cases by 2012. ANGTS and Canadian gas both compete at the margin for the incremental U.S. market.

Several aspects of these results deserve more detailed comment.

Regarding the relationship between crude oil price and fieldgate natural gas price, by 2012 the high case crude oil price is about 30 percent above the Control Case price, while the Alberta and Lower-48 fieldgate natural gas prices are only about 10 percent higher. The main reason why gas prices change by much less than oil prices is that competition in the natural gas industry prevents sellers from charging prices which exceed the incremental cost of gas, and this grows by less than the change in the oil price, even though the rate of gas consumption has increased with higher oil prices.

The change in consumption differs considerably from one sector to the other. In the markets which exhibit little switchability between gas and oil over our price range (i.e. the core market, and the electricity generation markets which use LFO or HFO priced as LFO), the increase in the gas price is the dominant price effect and it causes gas demand to decrease very modestly. In the gas:HFO switchable markets, the increase in the oil price is the dominant price effect, insofar as oil prices increase by much more than gas prices, causing a large loss of the switchable oil market to natural gas. The relationship between relative gas:HFO prices and non-core market development is shown in Figure 6-34. The U.S. non-core market grows from 4.9 Tcf (1987) to 6.5 Tcf (2002), then declines to 5.6 Tcf by 2012. The overall picture for Canada is similar, but with a slightly different profile of relative gas and oil prices.

Low Oil Price Sensitivity Test

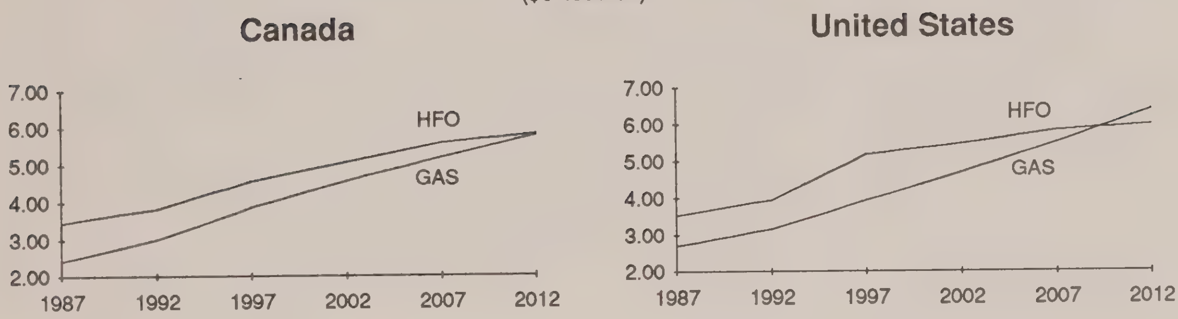
Conversely to the high oil price test, our expectation is that, relative to the Control Case, lower oil prices would reduce demand for and supply of natural gas, cause natural gas prices to decrease (but

Figure 6-34

High Oil Price Case

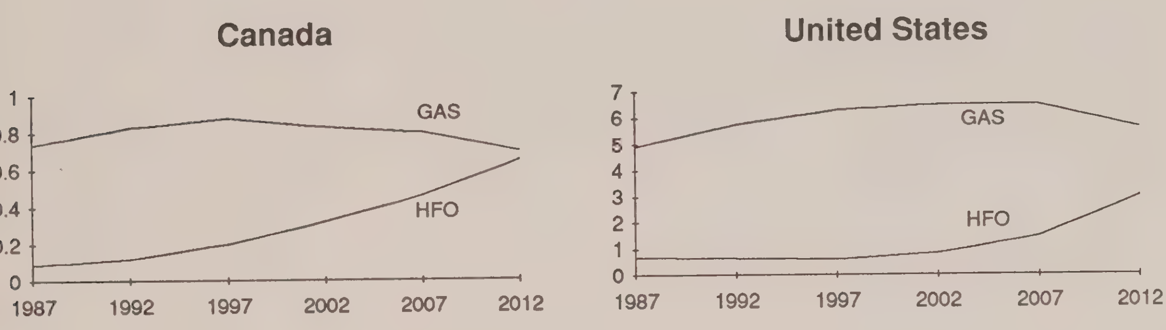
Noncore Gas and HFO Prices

($C 1990/GJ)



Noncore Gas and HFO Demand

(Tcf/Year)



Note: Prices are at the point of end-use

not necessarily in proportion to the decrease of oil prices), and cause Canada's gas exports to decrease. Lower oil prices should also reduce flows on TCPL between Alberta and Ontario, and delay the feasibility of northern gas supply (from the Mackenzie Delta and Alaska). These expectations are confirmed in our results, as shown in Table 6-18.

The major observations arising from Table 6-18 are that:

1. by 1997 the Alberta fieldgate price in the low oil price case is about 14 percent below that of the Control Case, and by 2012, 17 percent below;

2. by 2002, the impact of low oil prices on North American natural gas consumption is about 1.7 Tcf, or 7.2 percent below Control Case levels, and by 2012, 2.3 Tcf or 10.3 percent below;

3. the impact on TCPL flows from Alberta to Ontario is moderate till 2002, but grows thereafter, such that by 2012 in the low oil price case TCPL carries 1.1 Tcf/per year rather than 1.4 Tcf as in the Control Case;

4. the Mackenzie Delta project becomes viable only after 2007 in the low oil price case, whereas it was viable after 2002 in the Control Case;

Figure 6-35

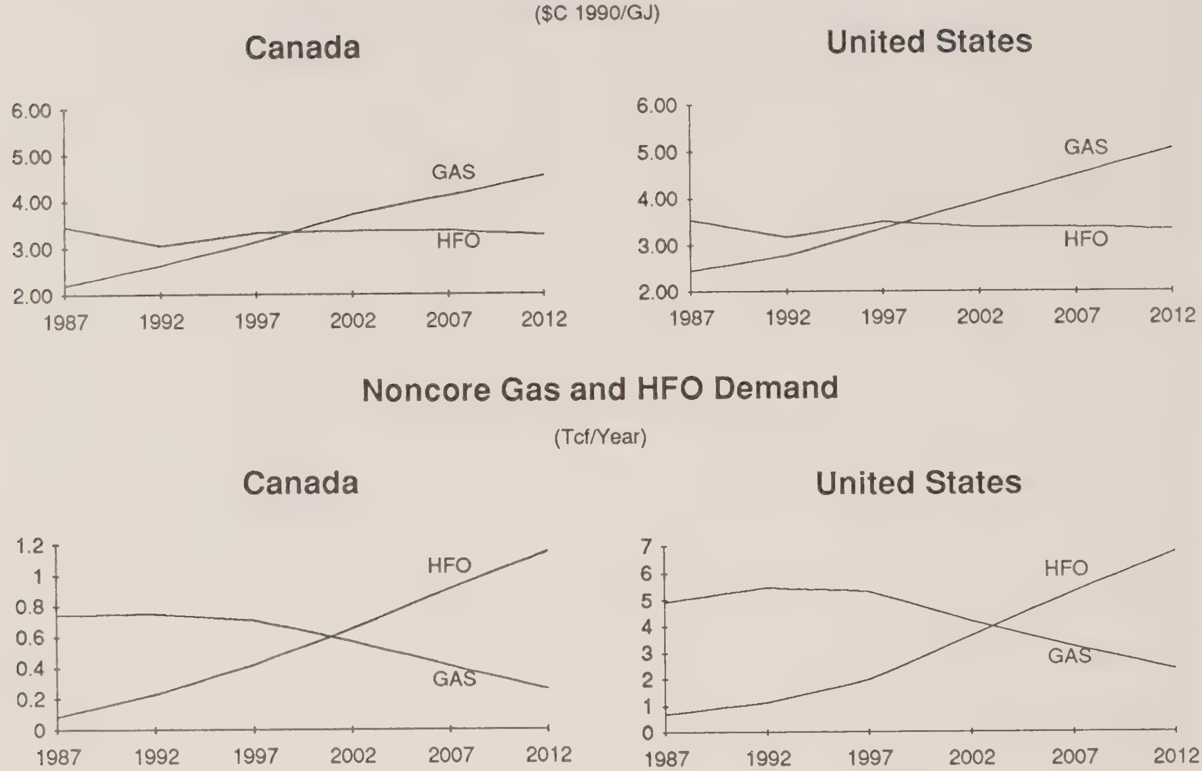
Low Oil Price Case

Noncore Gas and HFO Prices

($C 1990/GJ)

Noncore Gas and HFO Demand

(Tcf/Year)



Note: Prices are at the point of end-use

5. by 2002, the low oil price case generates a large decrease in Canada's net exports of natural gas relative to those in the Control Case, from 2.0 Tcf in the Control Case to 1.6 Tcf in the low oil price case; by 2012, however, net exports recover to 2.1 Tcf, only 200 Bcf below Control Case exports; the lack of ANGTS viability by 2012 in the low oil price case allows Canadian exports to grow from 1.6 Tcf in 2002 to 2.0 Tcf in 2012.

Between the low oil price and Control Cases, by 2012 there is a 30 percent difference in the crude oil price, but only a 17 percent difference in the Alberta fieldgate natural gas price. This happens because there is not enough flexibility in natural gas supply costs to meet the large decrease in oil prices represented by the low oil price case. As a result, the size of the natural gas market becomes smaller in the low oil price case relative to that in the Control Case.

All of this loss in market share happens in the HFO-switchable markets. The impact of low oil prices on the size of non-core markets is illustrated in Figure 6-35.

In both the U.S. and Canada, natural gas prices exceed oil

Table 6-18

Selected Results Comparison: Control Case vs Low Oil Price Case

	1997	2002	2012
Alberta Fieldgate Price[a]			
Control	2.35	3.04	4.24
Low Oil Price	2.02	2.69	3.50
North American End Use Demand[b]			
Control	22.3	23.5	22.5
Low Oil Price	21.8	21.8	21.7
Net Canadian Exports[b][c]			
Control	2.0	2.0	2.1
Low Oil Price	2.0	1.6	2.0
TCPL Flows to Ontario[b]			
Control	1.5	1.4	1.5
Low Oil Price	1.4	1.2	1.1
MacKenzie Delta Flows[b]			
Control	n/a	0.1	0.7
Low Oil Price	n/a	0.3	0.7
ANGTS Flows[b]			
Control	n/a	n/a	1.2
Low Oil Price	n/a	n/a	0.2

[a] $1990 Canadian/GJ
[b] Tcf per year
[c] Derived as explained in Section 6.4.1.4

prices in the late 1990s, followed by substantial erosion of non-core natural gas demand and increase in HFO demand. This happens notwithstanding the low distribution margins assumed for gas sales to this market, and the high ratio of HFO:crude oil prices which we have assumed.

Core market consumption, however, is about 4 percent to 6 percent higher in the low oil price case than in the Control Case, as lower natural gas prices moderately stimulate core market demand. The core market cannot switch to oil by definition. Were it not for this definition, however, in the U.S. there could well be substitution of LFO for natural gas, because in the U.S. LFO becomes considerably less expensive than core market gas beyond the year 2000. This does not happen in Canada, where core market gas is cheaper and LFO costlier on average than in the U.S.

6.5.2 High and Low Canadian Resource Sensitivity Tests

As outlined in section 6.3, the main purpose of our high and low Canadian resource sensitivity tests is to examine the impact of higher and lower estimates of the ultimate recoverable conventional resource potential from the WCSB on Canada's net exports of natural gas. These sensitivities provide insight into the impact of changes in resource potential and related direct costs for the WCSB relative to those of the Lower-48 States, and also demonstrate the impact on the timing of the development of Canada's frontier resources and the related transportation infrastructure.

For these sensitivity tests we use the range of estimates of ultimate recoverable resource potential and related direct costs discussed in sections 6.2.1 and 6.2.2, respectively. The high Canadian resource potential assumes that the ultimate recoverable resource potential in the WCSB is 300 EJ, whereas the low case uses an estimate of 200 EJ. The direct costs are adjusted accordingly relative to the Control Case. We wish to emphasize that although we have used a range of estimates of ultimate recoverable resource potential to derive the range of direct costs used in our analysis, there are a number of other factors which could give rise to lower or higher direct costs than were used in our Control Case. These are more fully described in section 6.2.2.

High Canadian Resource Sensitivity Test

Our expectation is that a higher resource potential would lower direct costs and should (given the assumption that U.S. resources and costs remain unchanged relative to the Control Case), increase the competitiveness of Canadian gas in the North American market, relative to the Control Case. The results of this analysis are shown in Table 6-19.

Table 6-19

Selected Results Comparison: Control Case vs High Canadian Resource Case and Low Canadian Resource Case

	1997	2002	2012
Alberta Fieldgate Price[a]			
Control	2.35	3.04	4.24
High Canadian Resource	2.30	2.86	3.90
Low Canadian Resource	2.45	3.19	4.46
North American End Use Demand[b]			
Control	22.3	23.5	22.5
High Canadian Resource	22.5	23.9	23.2
Low Canadian Resource	22.2	23.2	22.0
Net Canadian Exports[b][c]			
Control	2.0	2.0	2.1
High Canadian Resource	2.0	2.5	4.0
Low Canadian Resource	1.7	1.5	1.1
TCPL Flows to Ontario[b]			
Control	1.5	1.4	1.5
High Canadian Resource	1.5	1.6	2.0
Low Canadian Resource	1.3	1.1	1.3
MacKenzie Delta Flows[b]			
Control	n/a	0.1	0.7
High Canadian Resource	n/a	n/a	0.7
Low Canadian Resource	n/a	0.2	0.7
ANGTS Flows[b]			
Control	n/a	n/a	1.2
High Canadian Resource	n/a	n/a	0.4
Low Canadian Resource	n/a	n/a	1.6

[a] $1990 Canadian/GJ
[b] Tcf per year
[c] Derived as explained in Section 6.4.1.4

The major observations arising from the results of the high Canadian resource sensitivity test in Table 6-19 are that:

1) the impact on natural gas prices is very small in the near term, but the Alberta fieldgate price is 6 percent lower than that in the Control Case in 2002 and 8 percent lower in 2012;

2) the higher Canadian resource estimate has negligible impact on North American natural gas consumption until very late in the projection period; in 2012 it is some 0.7 Tcf, or 3 percent, higher than in the Control Case;

3) the impact on net exports is negligible in the near term but very significant in the longer term, as net exports increase by 25 percent in 2002 and by about 90 percent in 2012 relative to that in the Control Case;

4) there is no change in TCPL flows from Alberta to Ontario in 1997 but thereafter the flows increase relative to those in the Control Case and in 2012 are approximately 33 percent higher, at 2 Tcf per year; and

5) the Mackenzie Delta project becomes viable only after 2007 in the high resource case, whereas it was viable after 2002 in the Control Case, and ANGTS is deferred beyond the projection period.

The most notable feature of this case is the very large increase in net exports as compared to those in the Control Case over the latter part of the projection period. Due to the increase in Canadian resources and the commensurate reduction in direct costs, production from the WCSB is sustained, and in fact increases, late in the projection period, rather than beginning to decline as in the Control Case. This production level is supplemented by Mackenzie Delta production, which comes onstream somewhat later than in the Control Case due to the lower price path. WCSB gas is more cost competitive relative to U.S. and frontier gas and therefore supplies a larger proportion of North American consumption than in the Control Case.

Low Canadian Resource Sensitivity Test

As might be expected, the use of lower resources and higher direct costs than estimated in our Control Case tends to reduce net exports relative to the Control Case. The results of this analysis are also provided in Table 6-19.

The main observations arising from the results of the low Canadian resource sensitivity test in Table 6-19 are:

1) there is minimal impact on natural gas prices, with the Alberta fieldgate price being 5 percent higher than in the Control Case in 2012;

2) there is a small impact on North American natural gas consumption;

3) the impact on net exports is small in 1997 but progressively increases over the remainder of the projection period, with net exports being 25 percent lower in 2002 and about 50 percent lower in 2012 than in the Control Case;

4) there is not a large change in TCPL flows to Ontario; and

5) there is some acceleration of the timing of Mackenzie Delta and ANGTS relative to the Control Case.

The reduction in net exports in this case arises because the decline in production from the WCSB occurs earlier and is more severe than in the Control Case projection and is only partially offset by the acceleration of the timing of Mackenzie Delta production.

6.5.3 High U.S. and Canadian Resource Sensitivity Test and Low Backstop Sensitivity Test

As outlined in section 6.3, the main purpose of these sensitivity tests is to examine the impact of different assumptions regarding the North American natural gas resource and related direct costs, and secondly regarding backstop costs, on price formation and natural gas consumption.

High U.S. and Canadian Resource Sensitivity Test

While we consider the Control Case estimates of resources and direct costs for the WCSB and the Lower-48 States to be reasonable ones, we recognize as noted in sections 6. 2.1 and 6.2.2 that there is the potential for the resource to be larger and/or the impact of technological change greater than we have accounted for in this analysis. Additionally, the size of the U.S. natural gas resource and the related direct costs are important determinants of natural gas prices in the North American market, and we observed during our consultation process that there was considerable optimism regarding U.S. supply potential. For these reasons, we have examined the impact of higher resource estimates on price formation and natural gas consumption.

For this sensitivity test we have used the PGC maximum estimate of Lower-48 resource potential, adjusted as described in section 6.3, and scaled the Control Case direct cost curves so as to be consistent on a regional basis with these higher resource estimates. For Canada we have used the high resource estimates outlined in the previous section.

The key results of this sensitivity test are provided in Table 6-20.

Both the Lower-48 and Alberta fieldgate prices are substantially lower than in the Control Case, by 12 percent in 1997, 13 percent in 2002 and about 16 percent in 2012 (Figure 6-36). This is despite considerable growth in the size of the North American natural gas market relative to the Control Case due to the increased availability and reduced cost of natural gas. North American end use demand is higher than in the Control Case by 7 percent in 1997, 13 percent in 2007 and 23 percent in 2012. In any given time period, the price difference relative to the Control Case prices reflects the net impact of the decrease in cost due to the higher resource estimates (which reduces prices) and the demand stimulus resulting from greater abundance (which increases prices). The former outweighs the latter.

Low Backstop Sensitivity Test

As discussed in section 6.2.4, there is considerable uncertainty regarding the estimation of the backstop cost. Backstop supply sources are not expected to contribute to supply until well into the next century, and considerable technological change could occur over the intervening period which would have the effect of reducing the backstop cost relative to that which we have used in the Control Case. We have therefore conducted a sensitivity test using a backstop cost of $C(1990) 5.00/GJ, rather than $C(1990) 7.50/GJ as in the Control Case. The results are shown in Table 6-20.

The reduction in the backstop cost reduces both Lower 48 and Alberta fieldgate prices, but to a lesser extent than the high resource

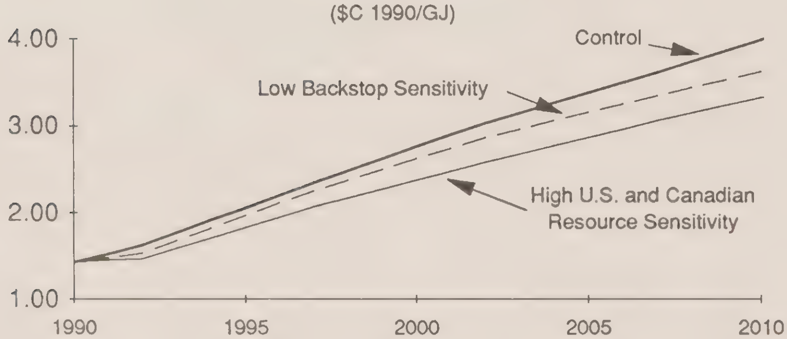
Table 6-20

Selected Results Comparison: Control Case vs High U.S. and Canadian Resource Case and Low Backstop Case

	1997	2002	2012
Lower 48 Fieldgate Price[a]			
Control	2.91	3.56	4.99
High Resource	2.56	3.10	4.19
Low Backstop	2.80	3.39	4.55
Alberta Fieldgate Price[a]			
Control	2.35	3.04	4.24
High Resource	2.07	2.63	3.50
Low Backstop	2.26	2.87	3.80
North American End Use Demand[b]			
Control	22.3	23.5	22.5
High Resource	23.8	26.5	27.7
Low Backstop	22.8	24.5	24.4

[a] $1990 Canadian/GJ
[b] Tcf per year

Figure 6-36
Natural Gas Price Projection Alberta Fieldgate
($C 1990/GJ)



sensitivity test (Figure 6-36). The Alberta fieldgate price is 10 percent lower in 2012 than in the Control Case. This is despite an increase in North American end use demand of 4 percent in 2002 and 8 percent in 2012, as compared to the Control Case. The change in price is much less than the change in backstop value because backstop supply becomes an important supply source so far beyond our projection period that its discounted impact on price formation is small.

6.6 Summary and Concluding Comments

Natural gas pricing is determined in the North American market, and our assessment of future prices is influenced by assumptions about the size and costs of natural gas resources and the growth in natural gas demand. A plausible range of natural gas prices results from our various scenarios, but we do project substantial real growth in natural gas prices over the study period. Our Control Case Alberta natural gas fieldgate price increases from $1.40 per gigajoule in 1992 to $4.20 in 2012, and our sensitivity cases produce a range of $3.50 to $4.65 by 2012 (all in 1990 Canadian dollars) (Figure 6-37).

We have attempted to reflect a measure of technological improvement in our analysis but recognize that some will suggest that we have not yet adequately accounted for the extent to which advances in technology may mitigate increases in costs and thereby prices over the longer term. We also anticipate that the ongoing supply surplus in Western Canada will continue to place downward pressure on natural gas prices in the short term, perhaps to a greater extent than accounted for in our results. However, our projection of both world crude oil prices and of North American natural gas prices over the longer term tend to be at the lower end of the range of published projections.

We project substantial growth in natural gas demand, especially in the U.S. electrical generation market, until around 2000. From

Figure 6-37
Alberta Fieldgate Gas Price
Range of Results
($C 1990/GJ)

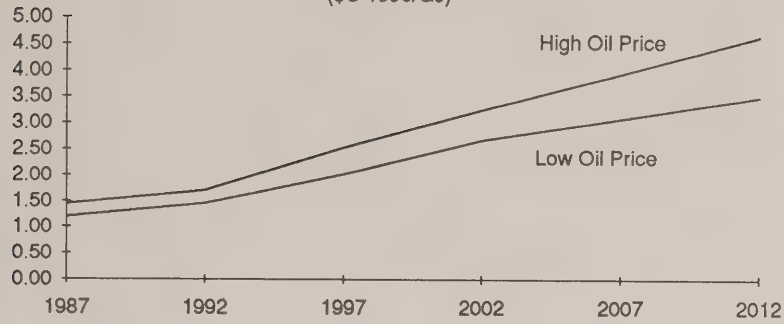


Figure 6-38
North American End Use Demand
Range of Results
(Exajoules/Year)

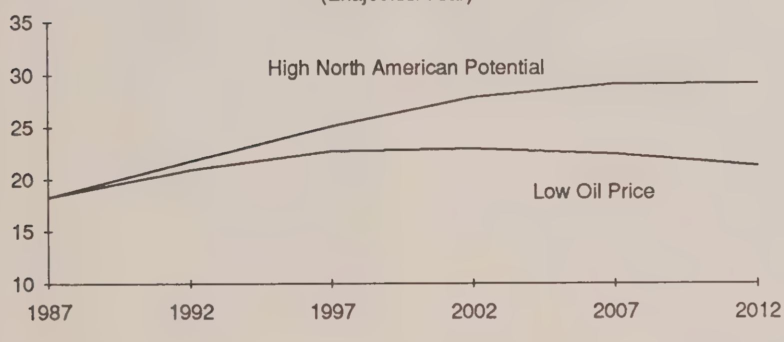
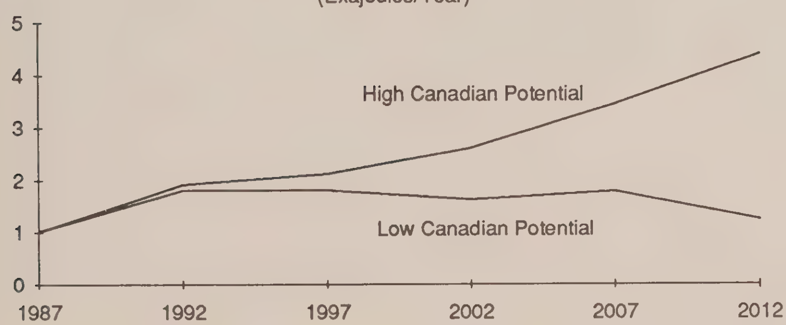


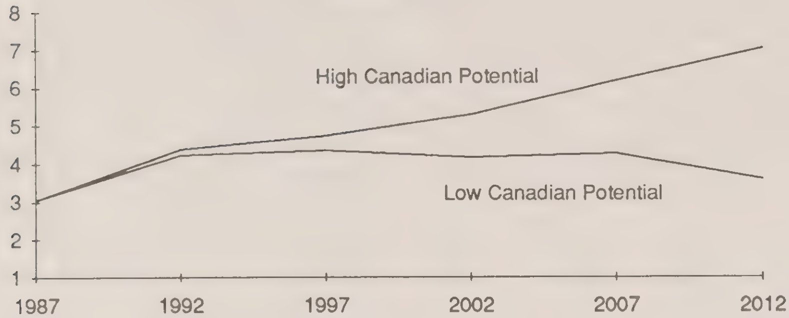
Figure 6-39
Net Canadian Exports
Range of Results
(Exajoules/Year)



2000 to 2010 natural gas demand growth moderates in the Control Case because natural gas prices exceed heavy fuel oil prices, causing substitution of heavy fuel oil for natural gas. The range of North American demand varies depending on the oil price and resource assumptions; by 2012 the range is from 20 Tcf to 28 Tcf (Figure 6-38). Canadian natural gas demand in the Control Case increases from 2.6 EJ in 1989 to 3.2 EJ in 2010, an average annual increase of 1 percent. Taking into account comparative gas supply and transportation costs between Canada and the U.S. and the growing size of the U.S. market, natural gas net exports grow from 1.4 EJ in 1989 to a peak of 2.4 EJ in 2007, and then recede to about 2.2 EJ by 2010 as supply from Western Canada begins to decline and frontier supply sources become competitive. Mackenzie Delta production in the Control Case commences in 2004 and Alaskan supply to the Lower-48 states commences very late in the study period. Imports to Ontario grow from 0.1 EJ in 1991 to 0.3 EJ in 2010. Total Canadian production is projected to increase from 4.0 EJ in 1989 to 5.6 EJ in 2007, and to moderate to 5.4 EJ in 2010.

These supply, demand, trade, and price results are sensitive to assumptions about uncertain variables, especially oil prices and natural gas resource and supply costs. Low oil prices cause natural gas prices to be lower than in the Control Case. Therefore, in the low oil price case natural gas loses market share to oil earlier in time than in the Control Case and Canadian exports are lower. Higher oil prices allow higher natural gas prices, increased gas consumption and higher Canadian exports relative to those in the Control Case. With regard to

Figure 6-40
Canadian Natural Gas Production Range of Results
(Exajoules/Year)



Northern projects, low oil prices cause Mackenzie Delta gas to be delayed to about 2010 and Alaska gas to beyond 2010, while high oil prices allow the development of Mackenzie Delta gas around 2002 and Alaska gas somewhat earlier than in the Control Case. Canada's export potential and overall natural gas production is most sensitive to what one assumes about the size and associated costs of the Canadian natural gas resource relative to that of the U.S. The impacts of a range of estimates of recoverable resources and related supply costs for Canada and the U.S. were assessed in sensitivity cases. By 2012, our results indicate that net Canadian exports could be as low as some 1.3 EJ per year or as high as about 4 EJ per year with low and high estimates of the WCSB natural gas resource, respectively (Figure 6-39). Total Canadian production ranges from 3.6 EJ to 7.0 EJ by 2012 (Figure 6-40). The analytical framework we are using is such that markets are presumed to adjust smoothly to whatever assumptions are used about the resource and oil prices. Of course, prices can fluctuate substantially over time as markets adjust to changing circumstances.

Our results indicate lower natural gas prices, a larger gas market and higher net exports than shown in the 1988 Report. There are several reasons for this. Between 1988 and now, the long-term demand outlook for the U.S. market has increased because of environmental considerations, greater expected reliance on natural gas for electricity generation and increased optimism about indigenous gas supply. We have used a more generous estimate of U.S. resource potential and have reduced U.S. supply costs somewhat relative to those used in the 1988 Report. For Canada, we have used a higher estimate of resource potential in the WCSB in the Control Case and reduced our estimates of input costs, such as for drilling, both of which have the effect of reducing supply costs and lowering prices as compared to the 1988 Report. We have also attempted to reflect a more competitive energy market environment in our natural gas transportation and distribution charges, which generally has the effect of reducing these costs relative to those in the 1988 Report.

Our results suggest the importance of caution in gauging the future development of the natural gas market. There are large uncertainties about factors which can have important impacts on results, and the analytical framework itself has limitations in portraying how the market functions or reacts to changed circumstances. Our main purpose in conveying these results is to indicate broad, plausible directions of change, to the extent our information and methods allow, and to illustrate the sensitivity of results to alternative assumptions about key uncertain factors. We do not view our Control Case as a most likely projection. It is a projection around which we have conducted certain sensitivity tests to illustrate a plausible range of results and to better understand the forces which determine the range. Users of our results can select the area of the projection they prefer based on their views of the range of assumptions we have tested.

Annex 1

User Cost

The rationale for the user cost component of the natural gas price is that gas is an exhaustible resource which has increasing marginal cost. The resource owner knows that his gas will increase in value up to that of the backstop, that his own supply costs will increase with cumulative production, and that what he sells at current prices will not be available to sell in the future at higher prices. His wealth is his gas in the ground. Therefore, given the market price he faces, it pays the individual resource owner to supply at any time only that amount of gas which recovers the producer's direct production costs and compensates the resource owner with a premium, the present value of which is equal to the foregone opportunity of earning a higher future value by selling the gas later in time. The discussion of user cost is simplified if we assume that at some future time, it will no longer pay to produce conventional resources because there will be a substitute fuel indefinitely available at a given, known price (the backstop resource).

Figure 1 illustrates how price, user costs and direct costs relate to each other from the perspective of the single producer and resource owner. Starting at the right-hand end of the diagram, at time T the resource is exhausted, and the market is at the backstop (B). This producer's direct costs of his last year of output is at CT, but the market price [1] is at PT = B. Hence, the difference between B and C is the rent (R) which this resource owner earns.

In time period t2, with direct costs at c2 and price at P2, the producer offers a quantity at which the price P2 is just enough to meet his direct costs c2 and leave the resource owner with a user cost premium (u2) equal to the present value of the rent he would have earned at time T. Likewise, in t1 at price P1, the producer will offer a quantity which recovers his direct costs c1 and earns a user cost premium u1 for the resource owner equal to the present value at time t1 of the rent R at time T. u1 is less than u2 because the discount factor is higher, given the longer time to exhaustion at t1 relative to t2.

The discount rate (i) is an important variable for managing supply. It should reflect the opportunity value of capital to resource owners. Relatively speaking, high discount rates indicate lucrative near term earning opportunities for gas converted to capital and they set a low present value on the future; hence, they encourage greater near-term supply and lower prices. The reverse is the case for low discount rates.

1 How the market gets to these prices is explained below in relation to Figure 2.

Annex 1 - Figure 1

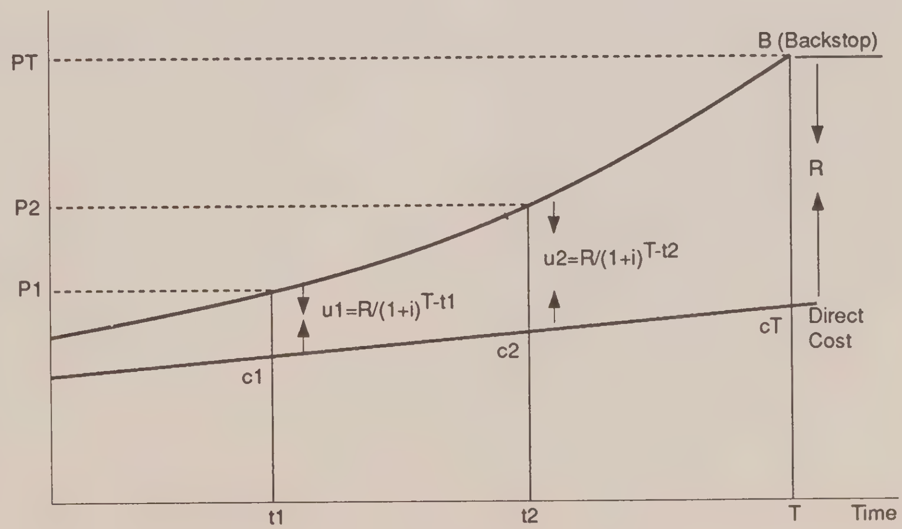
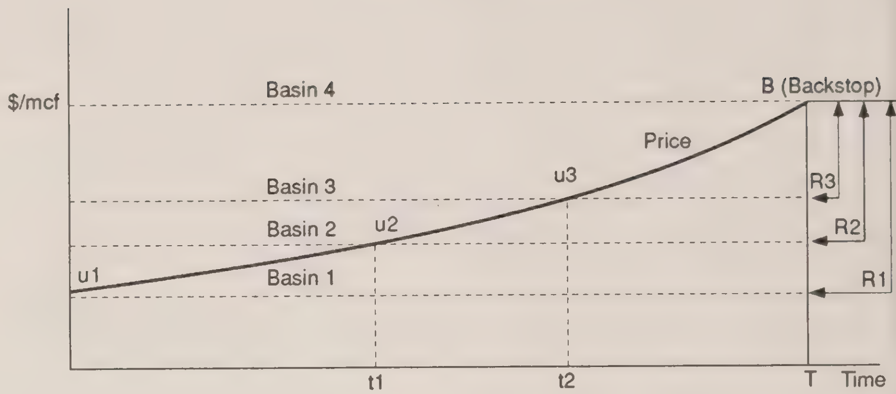


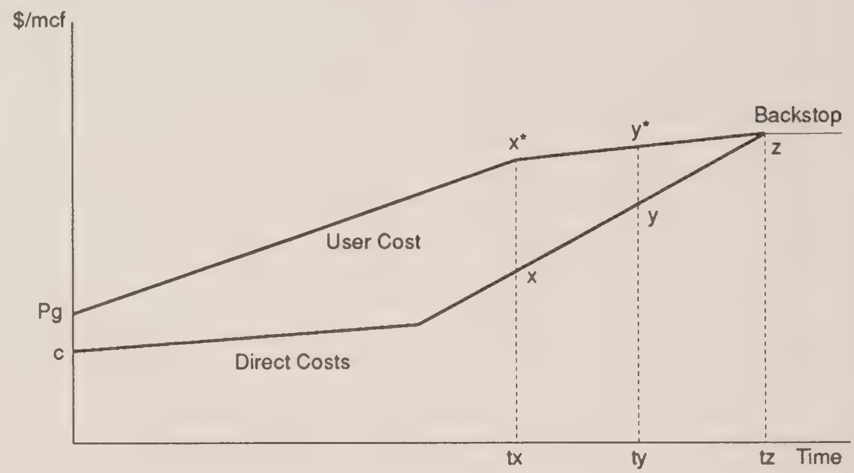
Figure 2 shows the evolution of the market price over time in a multi-source market. Starting at the left side of this diagram, demand is being met from Source 1, at increasing marginal cost, until cumulative consumption and increasing price makes it pay for Source 2 (a costlier source) to begin production. Both sources continue to produce at increasing marginal cost, until it pays for Source 3 to begin production, and the process continues until Source 4 is called upon (say it is a backstop resource such as a massive supply of coal-bed methane) and it then sets the market price. The price at which each successive source commences production determines the user cost for gas from each prior source. At the backstop there is no user cost, because there is no rent between price and marginal cost, by definition. The market price is being set by the direct and user cost of the incremental unit of gas, the timing of which depends upon annual demand and cumulative consumption at the prices so being determined.

Finally, Figure 3 shows the aggregate market supply curve and price path resulting from the processes described above. The line cz is the time path of aggregate, incremental direct supply cost; the difference between cz and price (Pgz) is the incremental per unit user cost, which in aggregate decreases as direct costs increase to the backstop (note that yy* is less than xx*). At the backstop (z) user cost is zero, because there is no rent - i.e. no difference between the marginal cost of the backstop and the market price. An economically optimal royalty regime would extract the user cost from the market.

Annex 1 - Figure 2



Annex 1- Figure 3



Annex 2

Natural Gas and Oil Prices

The price of gas exactly follows the price of oil only under the following conditions:

(1) the supply curve must fall within a perfectly elastic portion of the demand curve, in which case in equilibrium, the price of gas will be the same as the price of oil;

(2) if there were no perfectly elastic portion of the demand curve, the supply curve must be completely inelastic, in which case, a change in the oil price will trigger a similar change in the gas price; the gas and oil prices may be the same, but not necessarily in all circumstances.

Explanation:

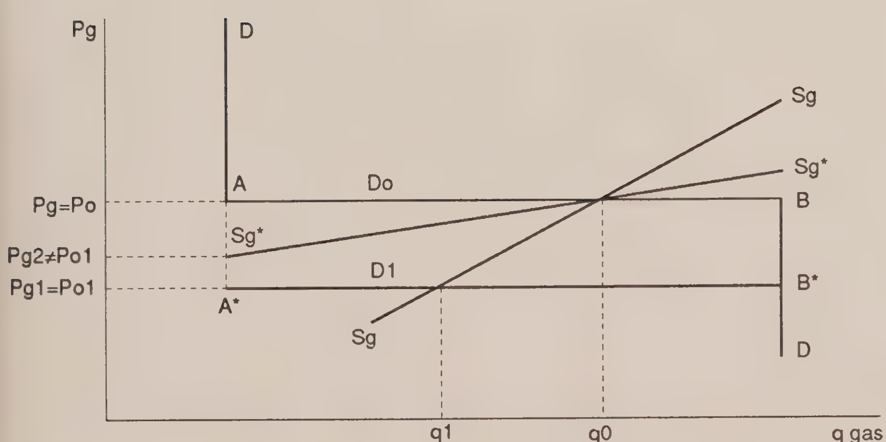
Rule (1), Figure (1)

The demand curve DD in Figure 1 characterizes aggregate natural gas demand. Natural gas demand can be segmented into two distinct markets. The "core market" is largely captive and by definition exhibits relatively inelastic gas demand (See portion DA).[1] The existence of the core market is predicated upon technological constraints which prevent switching from gas to an alternative fuel, a decisive fuel preference, or a durable absolute price advantage for natural gas relative to the relevant competing fuel. For example, in the residential market natural gas may have an absolute price advantage versus light fuel oil or electricity over the relevant range of gas and alternative fuel prices for the full time period of interest to the analysis. Portion BD of the demand curve is also completely inelastic at the low value end of the energy market. In this region, the size of the gas market cannot be expanded by reducing the gas price because the competition is very low value fuels.

The "non-core" gas market (portion AB) is switchable between gas and alternative fuel (i.e. heavy fuel oil). In this exaggerated portrayal of demand elasticity, if the price of natural gas were less than the price of heavy fuel oil (Po) then gas would capture the entire switchable market. Conversely, if the price of gas were above the heavy fuel oil price then the entire switchable gas market is lost to heavy fuel oil. If the gas and heavy fuel oil prices were equal then a range of equilibrium market shares for these fuels are plausible.

Demand for gas is perfectly elastic between A and B. In Figure 1 gas customers are consuming qO gas when the price of gas equals the price of oil at the level shown (Pg = Po). Now assume that the oil price

Annex 2 - Figure 1



1 One may question the long-term validity of this definition - and indeed the core market concept - because historically the so-called "core market" has undergone considerable shifts in composition of fuel use, and it does respond gradually to fuel price changes.

falls to Po_1. Then the perfectly elastic portion of the demand curve will fall to A* B*. This sets the new price level for perfectly elastic gas demand at Pg_1. If the gas supply curve looked like Sg, producers can afford to supply up to q_1, at gas price Pg_1, equal to the oil price Po_1. If they raised the gas price, their switchable market would disappear. They should not charge a lower price, because they would then attract the whole switchable market, but they lose money supplying any more than q_1 at Pg_1. Thus, in this case supply can meet a smaller portion of perfectly elastic demand, and the prices of gas and oil remain equal.

If the supply curve were like Sg*, at price Po_1 producers cannot afford to meet the oil competition and they lose the whole switchable market (A*B*); but, they retain the core market (the vertical portion of the demand curve DA as extended downward) and they can charge Pg_2, which is higher than Po_1. Gas and oil prices have decoupled, because the supply curve Sg* does not meet the non-core market at the new oil price demand conditions (i.e. the perfectly elastic portion A*B* of the demand curve). In a competitive market they could not charge more than Pg_2 even though core market demand is inelastic, because competition between gas suppliers would compete the offer price down to Pg_2 for that level of demand.

Rule (2), Figure (2)

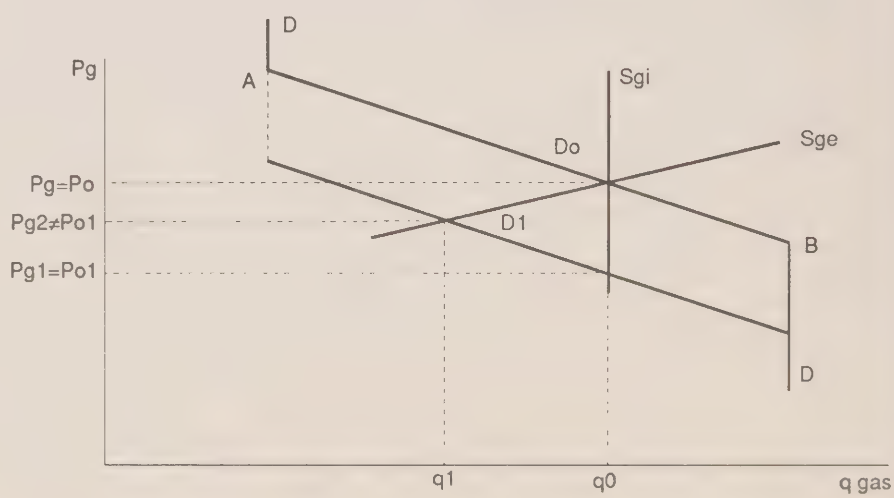
Non-core demand has some elasticity over a range AB, but it is not perfectly elastic (as in Figure 1).

At the outset, Pg = Po at the level shown in Figure 2, and gas consumers use qO gas. The supply curve Sgi is perfectly inelastic: producers will sell the same amount regardless of the price down to some minimum below which they will not supply. Now assume that the price of oil goes down to Po_1, causing the elastic portion of the demand curve to shift to the left: these people consume less gas at any gas price. With supply conditions being perfectly inelastic, producers meet the oil price and continue selling qO. They shouldn't lower the price further because in aggregate they can't supply the additional demand, and any producer who raised the price would lose market share and profits. In this case, the gas and oil price move equivalently, yielding equal gas and oil prices in equilibrium.

If they had a more elastic supply curve Sge, however, under the new demand conditions they could only afford to sell q_1 at price Pg_2, which is above the new oil price Po_1. They cannot lower the price to Po_1 because beyond q_1, they would be adding more to cost than to revenue for every incremental unit sold. Because of elastic supply conditions, gas and oil prices decouple.

It is arguable that Sgi is unrealistic except in the very short term because gas has future value greater than present value, meaning that there is some price below which the gas will be held in the ground rather than offered for immediate sale. It is also arguable that perfectly elastic demand is also unrealistic except for a rather small fraction of the total market. Therefore, in general, changes in gas prices will not exactly mirror changes in oil prices.

Annex 2 - Figure 2

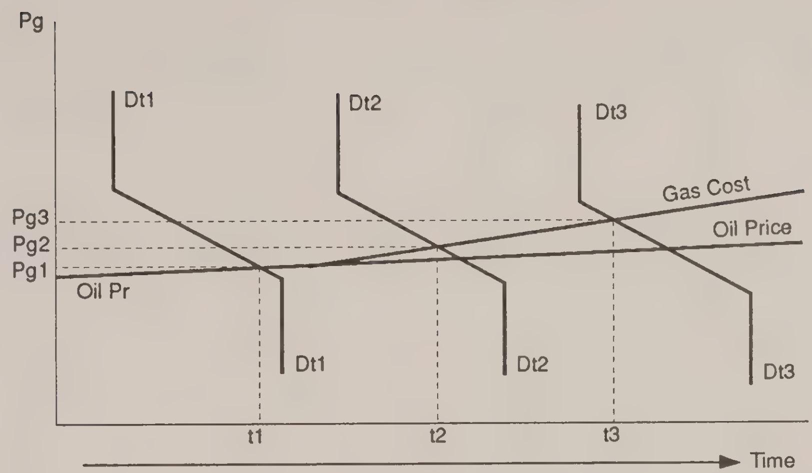


The foregoing is a short-term, partial equilibrium analysis.

The Longer Term (Figure 3)

Over the longer term, conditions such as those in Figure 3 may prevail. Over the time period up to t_1, oil and gas prices are very close or the same. Between t_1 and t_2, however, the cost of gas begins to increase and to exceed the oil price, even though it too is increasing ever so gradually. Let us recall that world market conditions and Middle East governmental decisions determine the price of oil, whereas the price of natural gas in North America largely depends upon North American supply and demand conditions for natural gas. The incremental cost of supplying natural gas can exceed world oil prices over a long time period; and some would argue that the reverse is also conceivable. Since the two commodities are not perfect substitutes, and given the transportation and conversion barriers to unfettered world competition for the North American natural gas market, there is no reason to suppose that gas and oil prices need be the same over time. Thus in Figure 3, by time periods t_2 and t_3, natural gas cost conditions are pushing the price of gas up to Pg_2 and Pg_3 respectively, increasing the difference between the gas and oil prices, and, all else equal, successively reducing the demand for natural gas over the elastic portion of the natural gas demand curve.

Annex 2 - Figure 3



Annex 3

Compilation of Electric Utility Gas Demand for Use in NARG Model Analysis

To use the NARG model in our natural gas market analysis, we must develop and input into the model an exogenous projection of fuel requirements for electricity generation disaggregated according to switchability between gas and HFO and between gas and LFO. The sources and procedure used to develop this projection are described herein.

The three main technologies for gas or oil fired electric generation are steam turbine, combustion turbine and combined cycle.

Steam turbine units can generally use natural gas or other fuels such as HFO. The large scale and continuous operation characteristics of steam turbine facilities limit their use in commercial and industrial applications, therefore we assume the use of steam turbines to be confined to electric utilities.

Combustion turbines and combined cycle units generally use either natural gas or LFO. Combustion turbine and combined cycle technology is employed by electric utilities, independent power producers (IPP), as well as by commercial and industrial cogenerators.

Our projection of gas and oil demand for electric generation includes:

1. gas volumes for commercial cogeneration[1]
2. gas volumes for industrial cogeneration
3. oil volumes for industrial cogeneration[2]
4. HFO volumes for electric utilities
5. LFO volumes for electric utilities
6. gas volumes for electric utilities - steam turbine (assumed switchable to HFO)
7. gas volumes for electric utilities - combustion turbine/combined cycle (assumed switchable to LFO)

Based on the above, we assume the electric generation market switchable between gas and HFO includes electric utilities using steam turbine technology (components 4 and 6 above). The electric generation market switchable between gas and LFO is assumed to include electric utilities using combustion turbine and combined cycle technologies as well as commercial and industrial cogenerators (components 1, 2, 3, 5 and 7 above).

For the projection of electric generation gas and oil demand in Canada, we use in-house NEB data for each of the above components.

The U.S. projection involves the compilation of data from three sources, as no one source provides all of the above components. The remainder of this section describes the sources of the U.S. data and the procedure we have used to combine these sources to provide a U.S. electric generation projection for the NARG model.

To maintain consistency with the projections in other market sectors, we continue to use the GRI Baseline[3] for electric generation gas and oil demand. The GRI Baseline projects gas and oil use by cogenerators in addition to gas, HFO and LFO use by electric utilities (components 1 to 5 above). The GRI Baseline also projects total gas demand by electric utilities, but does not distinguish electric utility gas use according to steam turbine or combustion turbine/combined cycle technology (components 6 and 7 above).

An alternative projection is provided by the North American Electric Reliability Council (NERC).[4] The NERC projection does disaggregate electric utility gas use according to steam turbine, combustion turbine and combined cycle technologies. Although we use the fuel consumption data by volume (million cubic feet), the NERC projection also provides this information by generating capacity (MW) and generation (gWh). However, the NERC projection does not provide projections of gas and oil use by cogenerators. The NERC projection is also relatively short term (to 1999) and aggregates the data according to NERC region

1 Oil use in commercial cogeneration is negligible.

2 Cogeneration is assumed to utilize combined cycle technology, therefore all oil used in industrial cogeneration is assumed to be LFO.

3 P.D. Holtberg, T.J. Woods, M.L. Lihn, and N.C. McCabe, *1991 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, Gas Research Institute, Chicago, Illinois, 1990.)

4 North American Electric Reliability Council, *1988 Electricity Supply and Demand*, 1988.

and sub-region which is a different regional representation than in the NARG model.

The EIA *Natural Gas Annual*[1] indicates historical gas consumption by electric utilities by state. Like GRI, the EIA makes no distinction in electric utility gas demand according to technology. GRI's value for 1987 electric utility gas consumption corresponds to that of the EIA.

For the NARG model base year (1987), we use the NERC data in order to allocate the GRI's electric utility gas demand by technology (components 6 and 7 above). As an example, we examine GRI's Mountain #1 region which includes Montana, Colorado, Wyoming, Idaho, Utah and Nevada.

GRI's Mountain #1 region includes part of NERC's Northwest Power Pool Area (which includes Nevada, Washington, Oregon, California (part), Idaho, Utah and Montana) as well as NERC's Rocky Mountain Power Area (comprised of Colorado and Wyoming). NERC reports the 1987 natural gas requirements for these areas (see Table 1).

Since NERC regions do not correspond to NARG regions, we must disaggregate the above NERC regional data by state and then recombine the state-based data into NARG regions. To perform this operation, we must assume that the shares of steam turbine and combustion turbine/combined cycle gas demand are the same for each state comprising a single NERC region or subregion.

We first determine EIA's 1987 volume of electric utility gas demand for each state in the NARG region.

	Bcf/year
Montana	0.478
Colorado	7.826
Wyoming	0.090
Idaho	0.004
Utah	0.263
Nevada	7.076
Total	15.737

We then apply the NERC-derived shares of steam turbine and combustion turbine/combined cycle gas use to the EIA-reported volumes of electric utility gas demand for each state in the NARG region. We then sum the state volumes to determine the 1987 volume of electric utility steam turbine and combustion turbine/ combined cycle gas demand in the NARG region (see Table 2).

For GRI's Mountain #1 region, the 1987 level of electric utility gas demand switchable to HFO is therefore 15.146 Bcf and the 1987 level of electric utility gas demand switchable to LFO is therefore 0.591 Bcf. We then add the 1987 levels of gas and oil fired cogeneration from GRI's Baseline to the electric generation market switchable between gas and LFO.

Beyond 1987, we expect all growth in gas-fired electric generation to occur in the market switchable between gas and LFO due to an increasing reliance on cogeneration and the lower capital costs, greater operational flexibility and higher fuel efficiencies associated with combustion turbine/combined cycle technologies. As a result, for the input demand path in the NARG model, we apply all increases in GRI's projection of gas demand for electric generation to the market switchable between gas and LFO. We also increase LFO use for electric generation in accordance with the GRI Baseline projection, averaging annual increases of 9.8 percent.

After 1987, we expect increasing electricity demands will cause the older gas-fired steam turbine units slated for retirement to instead be life-extended. As a result, for the input demand path in the NARG model, we maintain gas demand in the market switchable between gas and HFO at current levels throughout the projection period. Over this period, HFO use for electric generation increases in accordance with the GRI Baseline, averaging annual increases of 4.7 percent.

When we operate the model to derive the demand results, the demands for each fuel may change according to relative natural gas and HFO or LFO prices.

Annex 3 Table 1
Natural Gas Requirements in 1987

	Bcf/year	% of Total
Northwest Power Pool		
Steam turbine	1.337	93.1
Combustion turbine/combined cycle	0.099	6.9
Rocky Mountain Power		
Steam turbine	5.638	99.3
Combustion turbine/combined cycle	0.037	0.7

1 Energy Information Administration, *Natural Gas Annual 1988*, 1989.

Annex 3 Table 2
Determination of 1987 Volume of Gas Demand in NARG Region

Natural gas for steam turbines (switchable to HFO)

	Bcf/year (1)	Share (2)	Bcf switchable to HFO (3) = (1) x (2)
Montana	0.478	93.1	0.445
Colorado	7.826	99.3	7.775
Wyoming	0.090	99.3	0.089
Idaho	0.004	93.1	0.004
Utah	0.263	93.1	0.245
Nevada	7.076	93.1	6.588
Total	15.737		15.146

Natural gas for combustion turbine/combined cycle (switchable to LFO)

	Bcf/year (1)	Share (2)	Bcf switchable to HFO (3) = (1) x (2)
Montana	0.47	6.9	0.033
Colorado	7.826	0.7	0.051
Wyoming	0.090	0.7	0.001
Idaho	0.004	6.9	0.000
Utah	0.263	6.9	0.018
Nevada	7.076	6.9	0.488
Total	15.737		0.591

Chapter 7

Crude Oil and Equivalent

Crude oil price formation was discussed in Chapter 2, and product demand was described in Chapter 4. We focus in this chapter on a description of the crude oil and equivalent supply projection, and on refinery balances and crude oil supply and demand profiles. Figure 7-1 provides a framework for this discussion and can be used as a "road map" for the chapter. It shows how Canada's resources, through production from established reserves and reserves additions, contribute to the supply of crude oil and equivalent in both the domestic and export markets. It also illustrates how domestic crude oil supply, combined with imported crude oil, satisfies domestic refinery feedstock requirements, and indirectly, projected domestic product demand, with some allowance for the import and export of products to balance refinery operations.

The North American oil market differs from the gas market. In Chapter 6 gas supply and demand were discussed in the context of competitive natural gas prices that are set in a North American market in which gas competes for market share with coal, crude oil and other energy forms. In this chapter we discuss crude oil supply and demand determined in the context of crude oil prices set by competitive forces in world markets.

We begin this chapter with a review of the conventional crude oil and bitumen resources underlying our projections. We then discuss our projections of reserves additions. These two sections provide the basis for the supply projections which follow. Readers who are mainly interested in the supply/demand balance for crude oil may wish to begin with section 7.3, which discusses the projected supply of conventional light and heavy crude oil, synthetic crude oil from mining plants, crude bitumen, pentanes plus and synthetic crude from upgrading, along with the total availability of light crude oil and equivalent and blended heavy crude oil. This section also describes the price sensitivity of crude oil supply. Finally, we discuss the projections of refinery balances and crude oil supply/demand profiles, including the implications of our outlook for major crude oil pipeline systems.

7.1 Resources

We begin the discussion of crude oil supply by describing Canadian crude oil resources. The crude oil resource base encompasses all in-place volumes of crude oil, discovered and undiscovered and conventional as well as unconventional.[1] For purposes of the analysis in this report, we will focus on that portion of the resource base which is estimated at this point in time to be ultimately recoverable, or the ultimate recoverable resource potential. The future crude oil supply will be obtained from this resource and its size, geographical location and other characteristics are important considerations with respect to the supply projections which follow.

Conventional crude oil resources are categorized as light or heavy crude oil, based mainly on the refining processes required to produce useful products. Our heavy crude oil category includes both heavy crudes and crudes which are classified by some others as medium.

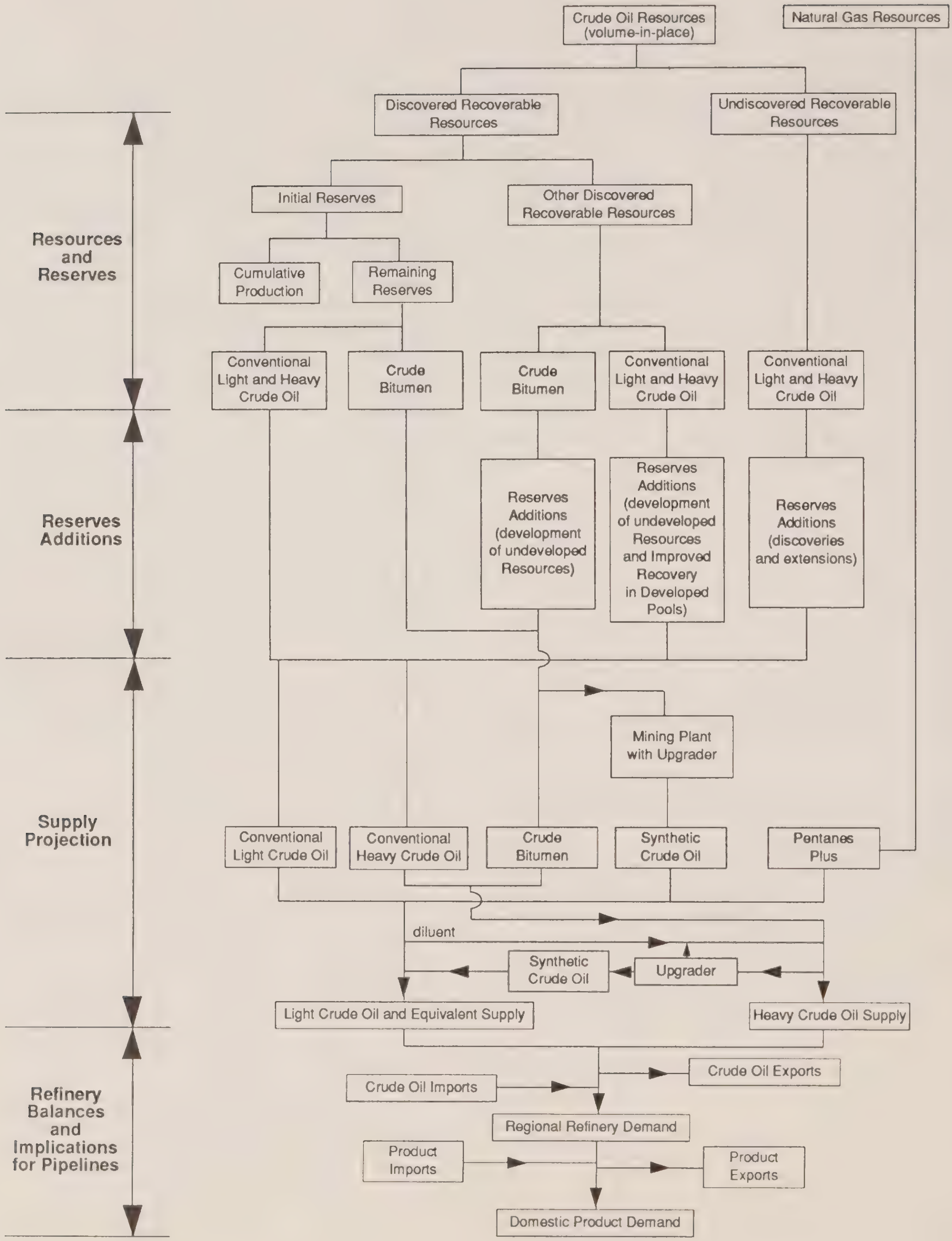
Unconventional crude oil resources differ from conventional resources in that they are more difficult to recover. They do not flow readily into a wellbore and cannot be shipped to a refinery without significant processing or preparation. Unconventional resources include bitumen[2], found in large oil sands and carbonate deposits in Alberta, and a material called kerogen, contained in oil shale deposits. Oil shale deposits

1 The terminology related to the classification of resources and reserves is not consistently agreed upon nor applied by those who make reference to these estimates. For purposes of this report, we have attempted to use terminology which is generally recognized and accepted by industry and governments in Canada. However, we recognize that there may be those who disagree with the classification terminology that we have used in this report. The reader is cautioned to closely examine the definitions provided in the text and in the appended glossary.

2 We include in the bitumen category all resources within the generally recognized bitumen-producing regions in Alberta, despite the fact that some wells produce at commercial rates without steam injection.

Figure 7-1

Schematic
Crude Oil Supply/Demand



are found in various parts of Canada, but the deposits are relatively small (the more significant deposits exist in the United States) and are unlikely to be economically viable in the timeframe considered in this report. Coal is also considered by some to be an unconventional crude oil resource, in that coal can be converted into a synthetic crude oil. However, we have not included projections of synthetic crude oil supply from coal in this report, because of the uncertain economic viability of this supply option over the projection period.[1] We therefore limit our supply discussion in the remainder of this chapter to conventional crude oil and bitumen.

Figure 7-2 depicts the location of significant current and anticipated crude oil supply sources. Table 7-1 summarizes Canadian crude oil resources, by component, by province and territory and by type of crude oil. The estimates of ultimate recoverable resource potential in this table are broadly divided into discovered and undiscovered recoverable resources. For comparative purposes we show both the recoverable resource potential and the related original oil-in-place, or crude oil resource

1 The coal resource base and coal liquefaction processes are discussed in Chapter 9.

Figure 7-2
Crude Oil Supply Sources

Table 7-1
Crude Oil and Bitumen Resource Estimates at Year End 1989

(millions of cubic metres)

	Discovered Recoverable Resources						
	Cumulative Production	Remaining Established Reserves	Other Discovered Resources	Total	Undiscovered Recoverable Resources	Ultimate Recoverable Resource Potential	Resource Base (c)
Conventional Crude Oil							
Light							
British Columbia Onshore	71	19	10	100	20	119	306
British Columbia Offshore	0	0	0	0	50	50	167
Alberta	1580	402	260	2242	454	2696	8546
Saskatchewan	130	34	25	188	39	227	1131
Manitoba	27	8	0	35	8	43	160
Ontario	10	1	0	11	0	11	41
Nova Scotia Offshore	0	3	21	24	294	318	1060
Newfoundland Offshore	0	80	155	235	659	894	2980
Mainland Territories	12	23	3	38	57	95	317
Mackenzie Delta & Beaufort Sea	0	0	256	256	856	1112	3707
Arctic Islds. & E. Arctic Offshore	0	1	65	66	807	873	2910
Other Areas (b)	0	0	0	0	167	167	557
Subtotal - Light	**1830**	**571**	**795**	**3195**	**3411**	**6606**	**21880**
Heavy							
Alberta	113	60	115	287	107	395	2192
Saskatchewan	241	74	205	520	163	683	3719
Subtotal - Heavy	**353**	**134**	**320**	**808**	**270**	**1078**	**5911**
Total - Conventional (a)(d)	**2183**	**705**	**1115**	**4002**	**3681**	**7683**	**27791**
Bitumen							
Mining Projects	162	482	9356	10000	0	10000	24000
In Situ Projects	38	60	38902	39000	0	39000	376000
Total - Bitumen (a)	**200**	**542**	**48258**	**49000**	**0**	**49000**	**400000**

Sources : See Appendix Table A7-1 for estimates of conventional resources in Western Canada.
NEB for estimates of original oil in place.
COGLA Annual Report, 1989 for estimates of resources in the Frontier Regions.
Alberta ERCB Report ST90-18 for estimates of bitumen resources.

Notes : (a) Numbers may not add due to rounding.
(b) Hudson Bay and the St. Lawrence Lowlands
(c) Original Oil in Place associated with Recoverable Resource Potential
(d) Appendix Table A7-2 provides more detail regarding the components of the conventional conventional crude oil resource base in the Western Canadian Sedimentary Basin.

base, used in our analysis. It is important to note that these are estimates at year-end 1989 and are revised from year to year, as production continues, new discoveries are made, other discovered resources are converted to reserves and our overall understanding of the size and characteristics of the resource improves.

Before discussing the components of the ultimate recoverable resource potential as described in Table 7-1 in more detail, we first make a number of general observations regarding the resource estimates for conventional crude oil and for bitumen.

The **conventional crude oil resource base** is estimated to contain nearly 28 billion cubic metres of original oil-in-place, of which only about eight billion cubic metres (28 percent) are currently estimated to be ultimately recoverable. Of this, some seven billion cubic metres are light crude oil and about one billion cubic metres are heavy crude oil.

For conventional light crude oil, nearly 3.2 billion cubic metres, or roughly half the estimated recoverable resource potential has been discovered. Of these discovered recoverable resources, more than half have been produced and a significant portion of the remainder is located offshore or in remote Arctic regions and will be very expensive to develop. Of the estimated undiscovered recoverable resources of 3.4 billion cubic metres, only about one-half billion cubic metres is anticipated to be found in the WCSB, while the remaining 2.9 billion cubic metres is in regions where crude oil will be expensive to find and develop.

For conventional heavy crude oil, 0.8 billion cubic metres or approximately three quarters of the estimated recoverable resource potential has been discovered. Of these discovered recoverable resources, about 0.35 billion cubic metres has been produced. A significant portion of the remaining 0.45 billion cubic metres is awaiting exploitation through improved recovery techniques, and the extent of the exploitation may to a large extent depend on an increase in crude oil prices.

The **bitumen resource base** consists of approximately 400 billion cubic metres of original oil-in-place, of which about 49 billion cubic metres are currently estimated to be ultimately recoverable. Additional undiscovered resources may exist, but these are expected to be insignificant in relation to the discovered resources. Most of the bitumen is contained in three large sand deposits (Athabasca, Cold Lake and Peace River) and a large carbonate deposit in the same general area. The very large Athabasca deposit contains the most viscous bitumen of the three major oil sand deposits, but was the first to be exploited because a large part of the deposit, containing some 24 billion cubic metres of bitumen, is sufficiently shallow that it can be surface mined. Surface mining is relatively efficient and could ultimately recover up to 40 percent of the mineable resource, whereas the in situ recovery methods which are anticipated to be used for much of the other 376 billion cubic metres of bitumen-in-place, will probably recover not more than about ten percent of the bitumen-in-place. Although the total bitumen resource is extremely large, the fact that only 0.2 billion cubic metres of the resource has been produced to date suggests that future exploitation may also occur at a rather slow pace.

Following is a discussion of the specific resource components, consistent with the presentation of Table 7-1.

7.1.1 Discovered Recoverable Resources

Discovered recoverable resources are those which are estimated at this time to be recoverable from known accumulations (that is accumulations which have been shown to exist by drilling, testing or production) using known technology. These resources total some four billion cubic metres of conventional crude oil and some 49 billion cubic metres of bitumen. Included in this category are cumulative production, remaining established reserves and other discovered recoverable resources, each of which is discussed in the following sections.

7.1.1.1 Cumulative Production

Cumulative production of conventional crude oil amounts to about 2200 million cubic metres, a little over one-half of the recoverable conventional crude oil resource discovered to date. Cumulative bitumen production amounts to 200 million cubic metres, a very small fraction of the discovered bitumen resource.

7.1.1.2 Remaining Established Reserves

Established reserves are that part of the discovered recoverable resource base that is estimated at this time to be economically recoverable using known technology under present and anticipated economic conditions. The recovery methods generally applicable to crude oil are described in the inset.

Those established reserves not yet produced are termed remaining established reserves. Initial established reserves are the sum of remaining established reserves and cumulative production.

Our estimates of established reserves of conventional light and heavy crude oil and crude bitumen are summarized in Table 7-1, by province and territory.

Conventional Crude Oil

Estimates of remaining established reserves of conventional crude oil, both light and heavy, are compiled from assessments of individual pools by Board staff, industry studies and estimates from provincial agencies, and are generally based on the assumption that current production operations will be continued.

We estimate the remaining established reserves of **conventional light crude oil** as of 31 December 1989 to be 571 million cubic metres. Historical conventional light crude oil reserves data is summarized in Appendix Table A7-1.

This estimate includes discovered recoverable resources of conventional light crude oil in the frontier regions which the Board recently recognized as established reserves. The established reserves for Newfoundland are those of the offshore Hibernia field, amounting to an estimated 80 million cubic metres. For Nova Scotia we recognize established reserves of three million cubic metres in the offshore Cohasset and Panuke fields. The estimates also include established reserves of one million cubic metres at Bent Horn in the Arctic Islands.

For established reserves of conventional light crude oil in the WCSB, on average approximately 19 percent of the oil-in-place is recovered by primary techniques. Improved recovery brings the expected overall recovery factor for conventional light crude oil in the WCSB up to 27 percent.

Average recovery factors vary significantly from province to prov-

Recovery Methods

Production methods have changed over time, as advances in recovery techniques have been implemented and well spacing, which was previously believed to have little effect on oil recovery, became recognized as an important consideration in optimizing oil recovery. The more advanced recovery techniques, which generally employ fluid injection to maintain reservoir pressure and to mobilize the crude oil, are commonly described as secondary and tertiary processes, or simply as enhanced oil recovery methods. This distinguishes them from primary recovery methods, which employ only the natural energy of the reservoir for production of the oil. Implementation of more advanced recovery techniques in producing pools is frequently conducted in conjunction with infill drilling programs to maximize oil recovery. With current advances in drilling technology, horizontal wells are likely to be more frequently used in the future to improve oil recovery. For ease of presentation, in our analysis we use the term “improved recovery” to refer to all increases in oil recovery resulting from infill drilling, horizontal wells, waterfloods, miscible floods, steam floods and other improved recovery techniques.

Apart from waterfloods, in which the injection of water is employed to displace oil from the reservoir, the most common improved recovery technique for light oil involves the injection of solvent miscible with oil under reservoir conditions. In Canada this solvent is usually some combination of methane, ethane, propane, and possibly smaller amounts of butanes and pentanes plus. Carbon dioxide can also be used as a miscible fluid but has been applied only on a very limited scale in Canada. For conventional heavy oils the most common improved recovery technique after waterflooding involves steam injection. An alternative thermal technique is in situ combustion. This technique involves burning part of the oil in the reservoir through air or oxygen injection to produce heat. Other more costly and more specialized processes such as surfactant, alkaline or polymer-assisted waterfloods are available for use in both light and heavy crude oil reservoirs. However, these are expected to provide only minor volumes of incremental recovery over the projection period.

ince, with the variation depending most importantly upon average reservoir quality, the extent to which improved recovery schemes have been implemented and the average viscosity of the light crude oil being recovered. Overall recovery factors for established light crude oil reserves in British Columbia, Alberta and Saskatchewan are 36[1], 28 and 18 percent respectively (derived from Appendix Table A7-2).

Figure 7-3 shows that remaining established reserves of conventional light crude oil declined from a peak of about 1500 million cubic metres in 1969 to about 600 million cubic metres in 1981, remained relatively constant between 1981 and 1986, and generally declined between 1986 and 1988. The increase in remaining reserves in 1989 is due to the inclusion by the Board of discovered recoverable resources in several pools in the East Coast offshore area in the established reserves category. Growth of initial established reserves of conventional light crude oil has occurred at a steady rate since the mid-1970s, when major downward revisions were made to these estimates.

We estimate the remaining established reserves of **conventional heavy crude oil** as of 31 December 1989 to be 134 million cubic metres. These reserves are all located in the WCSB. Historical conventional heavy crude oil reserves data is provided in Appendix Table A7-1.

For established reserves of conventional heavy crude oil, on average only 7 percent of the oil-in-place is recovered by primary recovery techniques. Improved recovery brings the estimated overall recovery of established heavy crude oil reserves to approximately 12 percent (derived from Appendix Table A7-2).

Since the late 1960s remaining established reserves of conventional heavy crude oil have remained relatively constant, as increases in initial established reserves have generally corresponded to production (Figure 7-3).

Crude Bitumen

We have adopted the estimates of the ERCB for established reserves of crude bitumen in the WCSB. Remaining established reserves of crude bitumen total 542 million cubic metres. Of the total, 482 million cubic metres will be recovered by mining techniques at the sites of the two existing plants and 60 million by in situ techniques at currently active projects, both commercial and experimental.

The mining plants are integrated mining/upgrading operations where bituminous sand mined from open pits is separated into bitumen and sand using a hot water process, and where the bitumen is then upgraded to a synthetic light crude oil by refinery processes.

In order to recover bitumen from areas where the overburden is too thick to allow surface mining, but is thick enough to withstand the pressure of injected fluids, wells are drilled and steam is injected to increase the temperature of the deposit and reduce the viscosity of the bitumen. The oil can then move to a wellbore and be pumped to the surface. This in situ recovery process has been successfully implemented at several commercial projects and there are a large number of experimental projects in operation that test recovery techniques before commercial projects are considered.

In situ recovery processes are being used in all three of Canada's bitumen deposits (Athabasca, Cold Lake and Peace River). However, the majority of commercial in situ production is from the Cold Lake deposit, located about 200 kilometres northeast of Edmonton. In this deposit the bitumen viscosity is low enough to allow effective steam injection. Bitumen is also produced commercially from the Peace River deposit, some 200 km northwest of Edmonton. Here steam is injected into a thin water-bearing zone underlying the bitumen from where it gradually moves upward, contacting a large portion of the reservoir. This recovery process may require more steam per unit of bitumen recovered, but the bottom-up heating of overlying bitumen is expected to result in higher recovery efficiencies than is the case with the more common steam injection technique used elsewhere. There is currently no bitumen being produced commercially from the Athabasca deposit, although a number of experimental projects are in operation. In some areas bitumen is also produced by primary means, without steam injection. However, this does currently not contribute significantly to the overall level of bitumen production.

7.1.1.3 Other Discovered Recoverable Resources

The discovered recoverable resources that are included in this category are those that are estimated at this time to be recoverable using known technology but have not yet been recognized as established reserves because of uncertain economic viability.

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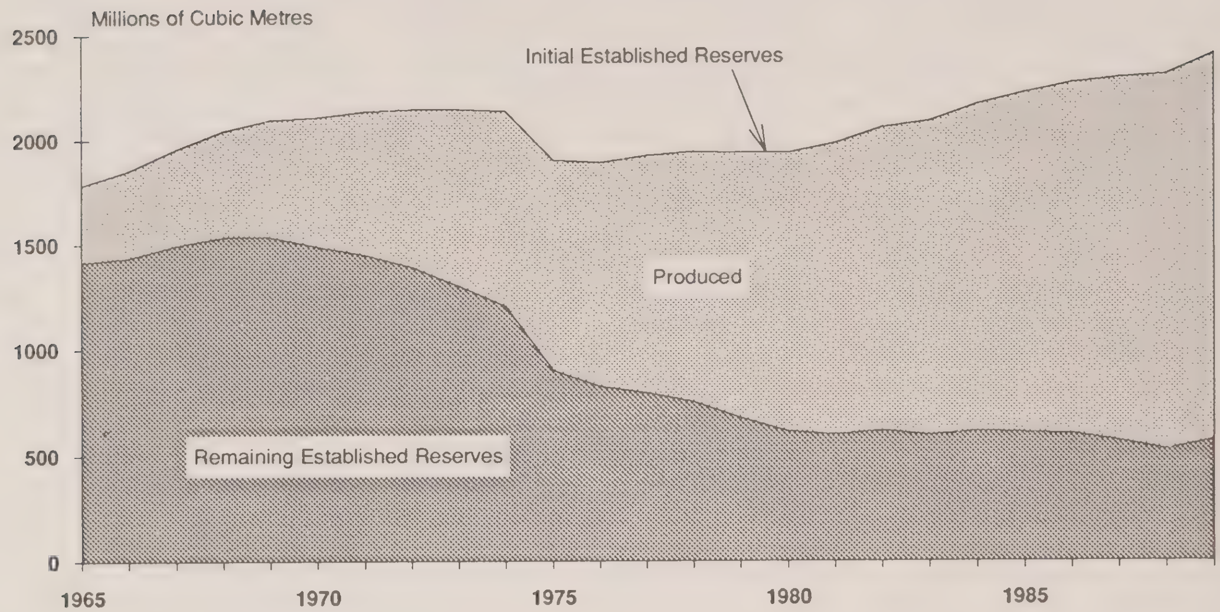
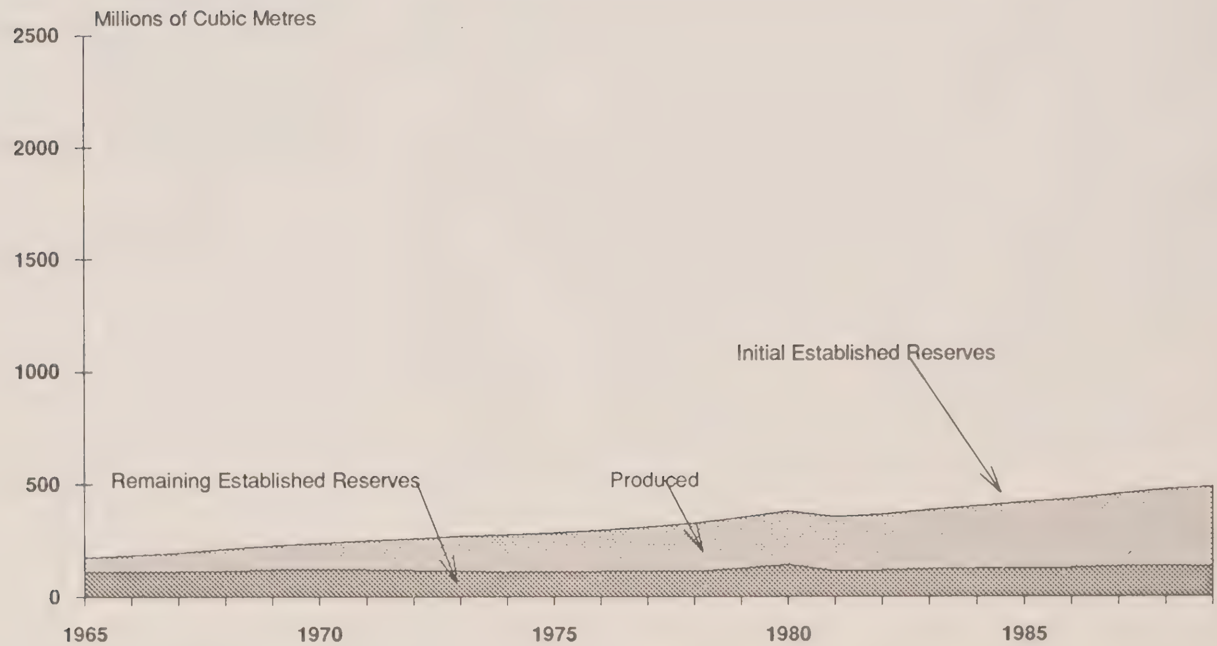
1 A recovery factor of 33 percent is more accurate as the estimate of oil-in-place published by BCEMPR does not include the oil-in-place for all pools.

Figure 7-3

Established Reserves of Conventional Light Crude Oil



Established Reserves of Conventional Heavy Crude Oil



Source: Appendix A7-1

Conventional Crude Oil

Conventional crude oil resources in this category are comprised of future crude oil volumes associated with improved recovery in currently established conventional light and heavy crude oil pools and of discovered recoverable resources in the frontier regions which have not yet been recognized as established reserves. For discovered recoverable resources in the frontier regions we have adopted the estimates made by the Canada Oil and Gas Lands Administration (COGLA) and reduced these by the volumes we currently recognize as established reserves. We assume that those not yet recognized as reserves will ultimately become economically recoverable as crude prices increase and/or development costs are reduced through technological progress.

Other discovered recoverable resources of **conventional light crude oil** totalled 795 million cubic metres as of year-end 1989. Of this total, 500 million cubic metres were estimated to be recoverable from discovered pools in the frontier regions and the remaining 295 million cubic metres by the future implementation of improved recovery techniques in the discovered pools of Western Canada. We estimate that the future application of improved recovery techniques in selected light oil pools in Western Canada will improve the overall recovery efficiency approximately four percentage points, to an average of 31 percent.

Other discovered recoverable resources of **conventional heavy crude oil** totalled 320 million cubic metres at the end of 1989. This estimate is completely attributable to future implementation of improved recovery techniques in selected pools in Western Canada. We estimate that future improved recovery in these pools will increase recovery by approximately eight percent, to an overall average of 20 percent (see Appendix Table A7-2). We anticipate that most of this incremental recovery will be achieved through the application of horizontal drilling, thermal enhanced recovery techniques, or a combination of both.

Crude Bitumen

We have adopted the estimates of the ERCB for discovered recoverable resources of crude bitumen in Western Canada. Other discovered recoverable resources are those located beyond existing projects and are estimated to total some 48 billion cubic metres, with about 9 billion cubic metres attributable to surface mining and 39 billion to in situ processes.

7.1.2 Undiscovered Recoverable Resources

Undiscovered recoverable resources are those that are estimated at this time to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but have not yet been shown to exist by drilling, testing or production. The estimates are based on the application of known technology. Both extensions to currently established pools and new discoveries are included in this category. In our estimates we have focussed on conventional crude oil, as the undiscovered recoverable bitumen resource is not believed to be significant enough to affect our supply projection, given the large volume of discovered bitumen.

Conventional Crude Oil

For estimates of undiscovered recoverable conventional crude oil in the WCSB and frontier regions we complemented estimates for light crude oil published by the Geological Survey of Canada (GSC) and COGLA with our own estimates for conventional heavy crude oil and for extensions to currently existing conventional light and heavy oil pools of the WCSB. We used statistical trend analysis and judgment, based partially on consultations with industry, to estimate the potential for new discoveries of conventional heavy crude oil in the WCSB. Estimates of resources in pool extensions were based upon historical growth rates.

Estimates of undiscovered recoverable resources are highly uncertain and can be expected to have a wide range, although the range will narrow as geological and geophysical data is accumulated through ongoing exploration. The estimates can change considerably over time as new technologies are developed and geological knowledge increases. Estimates of new discoveries are often expressed as ranges with associated probabilities of occurrence. When so expressed, we have used the "average expectation" for the specified range. The average expectation has a 50 percent probability of occurrence. Lower estimates than the average expectation have a higher probability of occurrence than 50 percent, while higher estimates than the average expectation have a lower probability of occurrence.

We have updated the GSC's estimate for **conventional light crude oil** in the WCSB from year-end 1985 to year end 1989 by subtracting our estimate of discov-

eries since that time.[1] In addition, we have made a small adjustment to the GSC estimate by adding our estimate for extensions to existing pools. We used CPA historical data to estimate growth rates for extensions. These growth rates were then applied to CPA's initial established reserves by year of discovery to obtain an estimate of the future growth of these reserves.

Our estimate of undiscovered recoverable resources of conventional light crude oil in the WCSB amounts to some 521 million cubic metres as of year-end 1989 (see Appendix Table A7-2). The GSC estimated the undiscovered recoverable resources of the WCSB at 570 million cubic metres as of year-end 1985. This did not include reserves additions from extensions in existing pools. The reserves additions from new discoveries in the intervening period amount to 100 million cubic metres, such that the adjusted GSC estimate at year-end 1989 is 471 million cubic metres. To this we have added approximately 50 million cubic metres, expected from extensions of existing light oil pools in Western Canada, to obtain the current estimate of undiscovered recoverable resources in the WCSB. The assumed recovery factor for future discoveries is 27 percent. This is consistent with the recovery expected to be achieved in currently established pools by primary and improved recovery methods. We anticipate that reservoirs discovered in the future in Western Canada will be smaller and possibly of poorer quality than those discovered in the past and might therefore be expected to have lower overall recovery. However, we also anticipate that implementation of recent technological advances will tend to have an offsetting effect.

We have disaggregated our total estimate of undiscovered recoverable resources for the WCSB to the provincial level by assuming that the potential for new discoveries is proportional to initial established primary reserves (Appendix Table A7-2). We have provided this breakdown because we consider it to be potentially useful for comparative purposes. However, this disaggregation is not supported by a detailed geological analysis and it therefore should be used with some caution.

Our estimate of the undiscovered recoverable resources of conventional light crude oil in the frontier regions is based on GSC and COGLA estimates. Of the total of 2837 million cubic metres, 856 million cubic metres is located in the Mackenzie Delta, 807 million cubic metres in the Arctic Islands, 659 million cubic metres offshore Newfoundland and 294 million cubic metres offshore Nova Scotia, with the remaining 217 million cubic metres distributed in various other areas. Although we have included all of these resources in the light crude oil category, it is possible that some heavy crude oil could be included in these estimates.

Including the GSC's estimate of 40 million cubic metres for the St. Lawrence Low Lands, Canada's undiscovered recoverable resources of conventional light crude oil total 3411 million cubic metres, or slightly more than the recoverable light crude oil resources discovered to date.

Our estimate of undiscovered recoverable resources of **conventional heavy crude oil** amounts to 270 million cubic metres at year-end 1989. This represents an increase of some 60 million cubic metres over the estimate at year-end 1986 which was provided in our 1988 Report. The vast majority of this resource is anticipated to be found in new pools. The unexpectedly high rate of heavy crude oil additions in Alberta over the past four or five years has prompted an increase to our previous estimate of undiscovered recoverable resources. A small proportion of the total, 10 million cubic metres, is estimated to be contained in extensions to existing pools.

The assumed recovery factor for these estimates is 14 percent, which compares with 12 percent being achieved by current technologies in existing pools. It is anticipated that with technological improvements, such as horizontal drilling, recovery efficiencies will be somewhat higher in future discoveries and extensions than the recovery factors expected to be achieved in existing pools.

Crude Bitumen

Although some undiscovered recoverable resources of crude bitumen could exist, we do not expect them to be significant as compared to the discovered recoverable resources and have not provided an estimate for the purposes of this analysis.

7.1.3 Ultimate Recoverable Resource Potential

The estimated ultimate recoverable resource potential of conventional light and heavy crude oil in Canada amounts to some 7.7 billion cubic metres, 6.6 billion of which is light oil. This is only 28 percent of the estimated crude oil resource base for conventional light and heavy crude, indicating

1 *Conventional Oil Resources of Western Canada (Light and Medium)*, GSC Paper 87-26,1988.

that a large portion of the oil-in-place is not expected to be recoverable using known technology under the economic conditions anticipated in our study.

The estimated ultimate recoverable resource potentials of conventional crude oil for the WCSB are compared with the corresponding estimates from our 1988 Report in Table 7-2. The ultimate recoverable resource potential for conventional light crude oil is some 50 million cubic metres higher than our estimate in the September 1988 Report, because of our recognition of the recoverable resources in extensions to currently existing pools of Western Canada in this report. Adjustments to our estimates of recoverable heavy crude oil resources have resulted in an overall increase of 24 million cubic metres in our estimate of the ultimate recoverable resource potential for conventional heavy crude oil.

The estimated ultimate recoverable resource potential of crude bitumen amounts to some 49 billion cubic metres, which is about six times the comparable volume of conventional crude oil. Essentially all of this unconventional recoverable resource is thought to have been discovered. Recoverable volumes of bitumen represent only about 12 percent of the bitumen-in-place.

7.1.4 Summary

In summary, Canada has a very large volume of crude oil in-place. Much of this, however, is unconventional in the form of bitumen, and a large portion of the conventional resource base is located in the frontier regions.

The known production technologies included in our projections are

Table 7-2

Comparison of Estimates of Conventional Crude Oil Resource Potentials Western Canada

(Millions of Cubic Metres)

	Current	1988 Report
Light		
Initial Established Reserves	2270	2219
Other discovered resources	295	295
Undiscovered resources (a)	521	523
Total Light (ultimate)	**3086**	**3037**
Heavy		
Initial Established Reserves	488	434
Other discovered resources	320	370
Undiscovered resources	270	250
Total Heavy (ultimate)	**1078**	**1054**
Total Light and Heavy (ultimate)	**4163**	**4091**

Notes: Numbers may not add due to rounding.
[a] Based on the 1988 Geological Survey of Canada's median estimate adjusted to year-end 1989 for the current projection and year-end 1986 for the 1988 Report.

Source: Appendix Table A7-2

such that a large proportion of the in-place resource is not expected to be recovered. For conventional crude oil about 28 percent is estimated to be recoverable, and for bitumen only 12 percent. Higher crude oil prices may provide incentives to improve recovery using known technology but there also appears to be considerable scope for the implementation of new methods to improve oil recovery. Whether this will materialize will depend on the rate of technological progress and the profitability of recovering additional oil using new technologies which may be applicable.

Canada's crude oil resource base is diverse and its components have particular characteristics which will influence their future contribution to supply. Conventional light and heavy crude oil resources of Western Canada are fairly well-defined, with somewhat limited scope for significant future exploratory discoveries. However, these resources are, for the most part, readily accessible and provide opportunity for the application of advanced improved recovery technologies. Canada's frontier regions provide the potential for the development of discovered resources and for substantial future exploratory discoveries. These resources are not readily accessible and their contribution to future supply will depend to a large extent on technological improvements to reduce capital and operating costs in the harsh environments of the frontier regions and on the relationship between these costs and prices. Canada's bitumen resource is very large, well defined and readily accessible. Issues with regard to its development are primarily related to the relationship between costs and prices and whether technological advances can reduce production and processing costs.

7.2 Reserves Additions

In the preceding section, we described the ultimate recoverable crude oil resource potential. Only part of this potential is currently recognized as reserves. This is the case either because the resource has been discovered but is not currently considered to be economically or technically viable ("Other Discovered Recoverable Resources") or because it has not yet been discovered ("Undiscovered Recoverable Resources"). Over the projection period, a portion of the resource included in both these categories will be added to reserves and can be expected to contribute to crude oil supply. The extent to which these reserves additions can be anticipated to occur is determined by the characteristics of the resource and by economic factors. The pace at which exploration proceeds, or the time at which a specific development proceeds, is largely dependent upon the perceived profitability of these activities.

In this section, we describe the basis for our projections of reserves additions. We begin with a discussion of supply economics. We then describe the projections of reserves additions over the period for conventional light crude oil, conventional heavy crude oil and bitumen.

7.2.1 Supply Economics

In our analysis of reserves additions we use an approach that attempts to reflect the profit motive that generally drives exploration and development activity. Industry evaluates the profitability of resource exploration and development by considering the capital costs required for exploration and development, the capital and operating costs associated with its production, the wellhead price to be received for this production, the taxes and royalties to be levied by the various levels of government and, finally, an appropriate rate of return on the investment in the project. We first discuss wellhead[1] prices for crude oil and then we describe how a profitability criterion is established, using the concept of supply cost as a measure of when exploration and/or development will become profitable, given our projected wellhead prices. Subsequently, we describe the basis for our estimates of the supply costs of various supply sources and finally describe the projection of drilling activity for the WCSB, which is largely determined by the difference between estimated supply costs for the undiscovered recoverable resources of conventional crude oil in the WCSB and projected wellhead prices.

7.2.1.1 Wellhead Prices

Wellhead prices and production volumes determine the revenues from petroleum exploitation and we use these prices in assessing the profitability of projects considered for inclusion in our supply projections. In our analysis we also compare supply costs to wellhead prices as a basis for determining when the start-up of specific projects might be expected to occur. Wellhead prices for particular supply sources are based on our crude oil price projection for WTI at Cushing, Oklahoma, with adjustments made for crude oil quality and transportation levies. Appendix Table A7-3 shows wellhead prices used in our economic

1 Wellhead prices are used to refer to prices received at the wellhead or the field or plant gate, whichever is applicable for a particular source of supply.

analyses, which are derived from the world crude oil prices discussed in Chapter 2.

The field price for conventional light and heavy crude oil in the WCSB is calculated by subtracting eight dollars per cubic metre from the Edmonton price of our reference crude oil. This charge is somewhat higher than the current average transportation cost and is intended to reflect primarily the transportation cost of crude oil from new discoveries. These discoveries generally face the cost of new pipeline connections, or high trucking charges, to deliver their crude oil to existing pipeline connections.

The transportation adjustments reflected in the wellhead prices for offshore East Coast production account for shipping costs to an East Coast port and price differences between that port and the price of WTI in Chicago. This adjustment has been estimated at about eight dollars per cubic metre.

The transportation adjustment for Mackenzie Delta/Beaufort Sea production is substantial, approximately $ 104 per cubic metre, as it includes the cost of pipeline transportation from the Mackenzie Delta to Edmonton. The estimated cost of connecting individual small pools in the Mackenzie Delta/ Beaufort Sea area to the main trunk line can also be significant and has been included in the supply cost calculation for small pools in that area.

For bitumen the quality adjustment versus light crude oil is significant. A number of considerations, which will be discussed in more detail in section 7.3.6.1, have led us to the view that the price differential between bitumen and Alberta sweet light blend in Edmonton, while uncertain, can be expected to increase from about $ 60 per cubic metre in 1990 to approximately $ 90 per cubic metre (in 1990 dollars) in the year 2010.

7.2.1.2 Supply Cost Methodology

In this section we explain how supply cost estimates are derived and how they are used to develop our projections of reserves additions.

Since a supply cost expresses some or all costs associated with resource exploitation as a levelled out cost per unit of production, it is sensitive to the discount rate used in the analysis. The discount rate is in part dependent upon the purpose for which the supply cost is being estimated.

In our supply cost we have included the capital costs associated with resource exploration where appropriate, the capital costs for development, the capital and operating costs associated with resource production, and royalties. Whereas for natural gas we used the user cost as a proxy for royalty, for crude oil royalties have been calculated directly using an estimate of the royalty rate applicable to various sources of supply.

In order to estimate supply costs which will provide a reasonable return on investments from an industry perspective, we use a discount rate that reflects the corporate pre-tax cost of capital. The corporate cost of capital is based on an average industry debt-equity ratio, long-term cost of debt and a minimum acceptable return on equity. Our approach to this calculation is shown in the inset. The ten percent real before tax cost of capital, as derived in the inset, is used in all of our supply cost calculations and should, given our assumptions, provide on average for an eight per cent real after tax rate of return on equity. We calculate supply costs in this generic manner to provide a consistent basis for comparison between competing projects and the supply cost is compared to our price projection in order to arrive at a preliminary start-up date for the project.

In scheduling major projects, we assume that investors will have sufficient foresight in most circumstances to commence the project development prior to the time at which supply costs and wellhead prices are equivalent.

As outlined in the inset on scheduling of major projects, the final start-up date for projects is influenced by many additional factors, which we also attempt to reflect in our analysis. We conduct an after-tax economic analysis of all major projects. This analysis uses projected crude oil prices and takes account of the specific effects of the fiscal regime and other factors not considered in our generic supply cost methodology. It is noted that these after tax analyses, which use projected prices, generally result in project rates of return on equity that are in excess of 15 percent nominal (about 11 percent real), which is higher than would be expected from our generic calculations. These higher rates of return can be attributed to the use of projected prices and the fact that the effective tax rate for specific projects may be reduced somewhat by fiscal incentives which are not entirely captured in the generic analysis.

Calculation of The Before Tax Cost Of Capital

The cost of capital has two components: cost of equity and cost of non-equity capital.

- Equity capital is expected to earn a minimum rate of return of eight percent after tax in constant dollars.[1]
- Interest to be paid on non-equity capital is expected to decline from the current 12 percent to eight percent, which means that the real cost of money is three percent based on an average inflation rate of five percent.
- We further assume that the Canadian oil and gas industry will have a 40:60 debt:equity ratio[2] and that the average income tax rate will remain at 45 percent. [3]

Given these assumptions we can calculate the before tax cost of equity capital in nominal dollars as follows:

The before tax cost of equity capital i_b can be calculated by the following expression

$$(1 + i_b)^n - 1 = ((1 + i_a)^n - 1)/(1 - \text{tax rate})$$

where i_a is the expected minimum after tax rate of return on equity capital, and n is the year for which the calculation is done. For year one this simplifies to

$$i_b = i_a/(1 - \text{tax rate})$$

The nominal after tax rate of return for equity capital, assuming eight percent rate of return and five percent inflation, is (1.08 X 1.05 - 1) X 100% = 13.4%. The nominal before tax rate for equity capital ranges from 24.4% for year one to 16% for year 25. The average value for the 25 year period is 18.4%.

If we combine the average value of 18.4% for 60% equity capital with the 8% interest to be paid for the 40% non equity capital, we obtain the long term nominal corporate cost of capital, which is equal to 0.4 X 8% + 0.6 X 18.4% = 14.2%. For shorter term projects this rate would increase slightly. Based on this analysis, *a ten percent real before tax cost of capital* (about 15% nominal before tax) appears reasonable and we have therefore used a ten percent discount rate to calculate supply costs.

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1 The petroleum industry's return on equity has been on average about nine percent in nominal terms, or 4.5 percent real which is nearly two percent below the manufacturing industry over the last ten years. However, industry performance was below average in that period. In the ten years prior to that, the petroleum industry earned a 16 percent nominal rate of return (eight percent real), compared to 13 percent for the manufacturing industry. From another perspective one can look at risk premiums appropriate for the petroleum industry. Based on a review of seven evaluations of historical risk premiums we found that these premiums averaged 6.5 percent real. This would be a premium over a risk free investment, which would likely earn about two percent real after tax. Both of the above approaches would indicate that an eight percent real rate of return after tax would be sufficient to finance petroleum investments and is a reasonable return to use in our analysis.

2 From data published by the Petroleum Monitoring Agency it appears that the 40:60 debt/equity ratio is representative of industry project financing before 1984. However, at that time, declining prices of oil and gas and industry restructuring had increased the overall industry debt load to 61:39. This has since led to less debt financing. Currently the industry's debt load stands at a debt/equity ratio of 53:47. We presume that in the longer term the debt/equity ratio will return to the historical level of 40:60.

3 Summation of federal and provincial corporate tax rates.

SCHEDULING OF MAJOR PROJECTS

In developing our supply projections, we give particular consideration to the scheduling of major projects. When projecting the timing of major projects, one has to consider the long lead times and large front end investments normally associated with such projects and the inherent uncertainty in projections of oil and gas prices.

In our scheduling methodology, we presume that companies will have reasonable confidence in the projected price path. Under such conditions, it is perceived that companies will proceed with a project if it is technically and economically feasible and if the risk exposure is acceptable. These criteria are addressed as follows:

- Technical feasibility is considered on the basis of announced plans, on discussions with industry and our own assessment of the technical viability of these projects.

- Economic feasibility and risk are interrelated, in that economic viability depends ultimately on whether the rate of return and other economic indicators are commensurate with the perceived risk. In our analysis, we approach this problem in stages:

  - As a first approximation, we compare a project's supply cost to projected prices for the project's output and assume that the start of project construction can be estimated by making the start of production coincide with the time that projected prices (in real terms) for the project's output are equal to its supply costs (see Figure 7-4). This implies that a project will yield the specified corporate hurdle rate if prices remain at the level projected for the year of production start up. It also implies that the private investor is taking some risk in advancing a project by the period of the project lead time in anticipation of future price increases. Conversely, profitability will be significantly improved if prices continue to increase beyond the project start-up date. Figure 7-4 illustrates these points.

  - To arrive at a final projected start-up date for our supply projection, we consider a number of other factors. These include announced industry plans, industry comments on projected start-up dates received during our consultation process, possible conflicts with other major projects regarding manpower and/or availability of financing, technological progress and last, but not least, the after tax rate of return of a project. The after tax rate of return generally exceeds 15 percent nominal because the tax/royalty regime provides incentives which are not sufficiently reflected in the discount rate calculation.

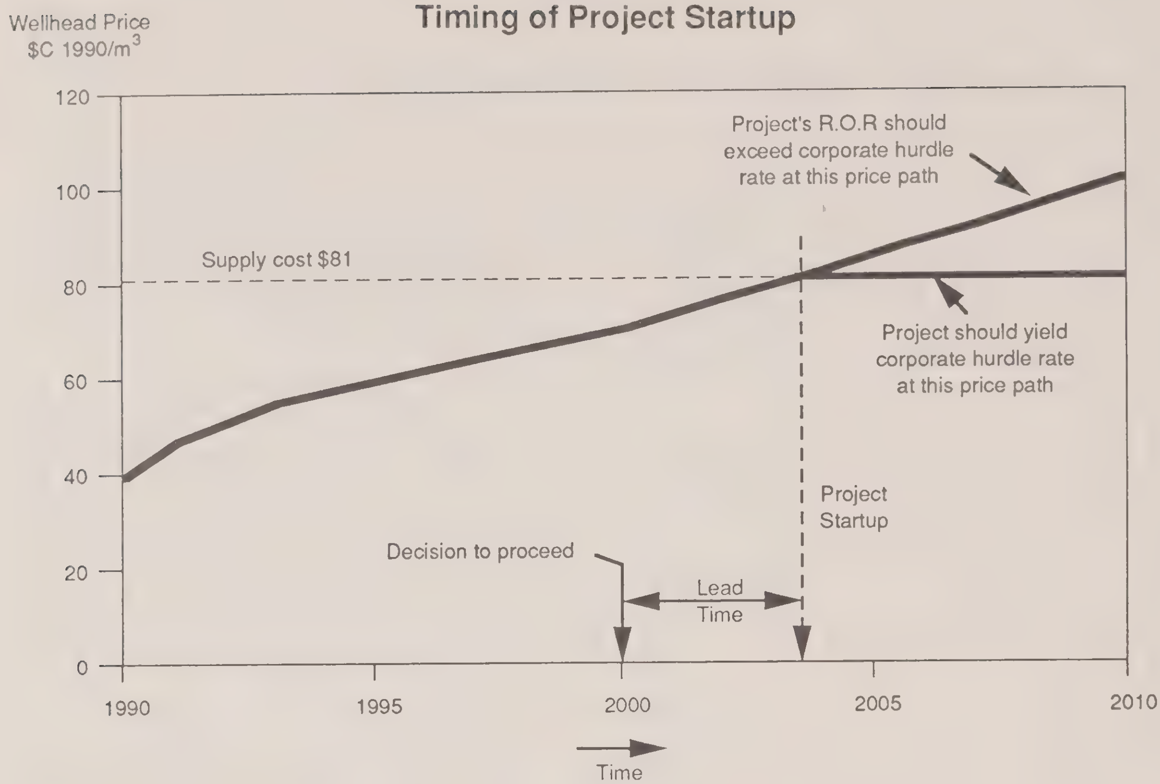
  - This rate of return is calculated using projected oil and gas prices. The after tax rates of return should be commensurate with the perceived risk that various uncertainties pose to the profitability of a project.

  - Based on all of the above considerations, the timing of a project is often revised from the initial estimate which is based solely on an assessment of a project's supply costs.

We consider the above method to be a reasonable approach to scheduling of major projects. However, it is not definitive and is based on many judgmental factors. In particular, we have found that the use of supply cost estimates and their relationship to the projected price path provides an effective means of comparing our analysis to that of others.

Figure 7-4

Timing of Project Startup



7.2.1.3 Supply Costs

In this section we discuss our estimates of supply costs for the discovered and undiscovered recoverable resource categories which form the basis for our projections of reserves additions. We first describe the estimates of supply costs for conventional light and heavy crude oil resources in the WCSB, then the supply costs for conventional light crude oil resources in the frontier areas, and finally, the supply costs for bitumen resources from mining with integrated upgrading and from in situ development with separate upgrading.

To estimate supply costs of exploratory drilling prospects in the WCSB, we conduct an aggregate assessment of the costs of increments of supply. We summarize the results of this analysis in a supply cost curve which graphically expresses the relationship between incremental discoveries and supply costs. For all other supply sources, we estimate supply costs on an individual project basis.

Our estimates of supply costs for various sources of supply included in our projection are summarized in Table 7-3. This table shows the range of supply costs for each supply source at the wellhead or plant gate and at Edmonton. In order to compare these costs to our crude oil price projection, we also show them in U.S. dollars per barrel at Cushing.

Conventional Light and Heavy Crude Oil

To estimate the supply cost of discovered recoverable **light and heavy crude oil resources in Western Canada,** we evaluate the costs associated with future implementation of improved recovery methods in established pools in the WCSB. A screening process is used to identify pools which are prospects for the application of improved recovery methods and an estimate is made of the supply cost of the incremental oil from each identified prospect. The estimates vary from project to project, with $C 100 per cubic metre ($US 12.50 per barrel) being the minimum for both heavy and light crudes and $C 200 per cubic metre being a maximum imposed by our crude oil price projection

Table 7-3

Summary of
Crude Oil Supply Cost Estimates
for Projects Considered in Projection

(Dollars of 1990)

	Field * Supply Costs	Transportation Costs to Edmonton	Supply Costs at Edmonton	Supply Costs at Cushing
	($C/m3)	($C/m3)	($C/m3)	($US/b)
Conventional Crude Oil				
WCSB				
Discovered Resources (Improved Recovery)	100-200	3	103-203	14-27
Undiscovered Resources	136-200	8	144-208	19-27
Frontiers				
East Coast Offshore	110-200	NA	NA	15-27
Mackenzie / Beaufort	80-140	104-66	184-206	24-27
Unconventional Crude Oil				
Bitumen	65-90	NA	NA	NA
Upgraded bitumen				
Upgraders	NA	NA	170-185	23-25
Integrated mining plants	200	NA	200	27

* Upper limits based on a crude oil price of $US 27 per barrel, which is reached at the end of the projection period .

(world crude oil prices at Cushing reach $US 27 per barrel in 2010). Supply costs of crude oil from hydrocarbon miscible projects depend partly on the costs of injected materials and supply costs from steam injection projects depend in part on the cost of the fuel (natural gas, or perhaps in the future coal) used to generate steam.

To estimate the supply cost of undiscovered recoverable resources in the WCSB we estimate the supply cost for increments of reserves additions and use these costs to develop a supply cost curve. A major determinant of the supply costs for undiscovered recoverable resources is the reserves added per metre of exploratory drilling. Other important determinants are the input costs, such as the cost of exploratory and development drilling per metre, associated with the exploration, development and production of the resource. With regard to the recoverable reserves added per metre of oil directed exploratory drilling, we assume a linear decline in the rate as shown in Figure 7-5 from current levels to zero at approximately 2400 million cubic metres, the estimated ultimate potential for conventional light and heavy crude oil recoverable by primary mechanisms (see Appendix Table A7-2). We have relied on CPA statistical data for the estimation of the input costs associated with the exploration, development and production of future reserves additions. The CPA data is not classified into the light and heavy categories and we have made no adjustments to our estimates to compensate for this fact. Our estimates therefore reflect averages for conventional light and heavy crude oils in the WCSB. The input costs used for our calculations are given in Table 7-4. These are long term averages of the historical data. The historical annual data for the cost per metre of oil directed exploration and development drilling in the WCSB is shown in Figure 7-6.[1]

The variability of the historical additions rates displayed in Figure 7-5 and of the historical costs displayed in Figure 7-6 illustrates the uncertainty associated with estimates of supply costs for reserves additions. The uncertainties relate to the assumed ultimate potentials, the impact of technological change on costs and the

1 A more detailed description of the methodology for the formation of a supply cost curve is found in the paper "Trends in Crude Oil and Natural Gas Reserves Additions Rates and Marginal Supply Costs for Western Canada" by B. Bowers and R. Kutney published in the Canadian Journal of Petroleum Technology, Volume 28, 1989.

Figure 7-5

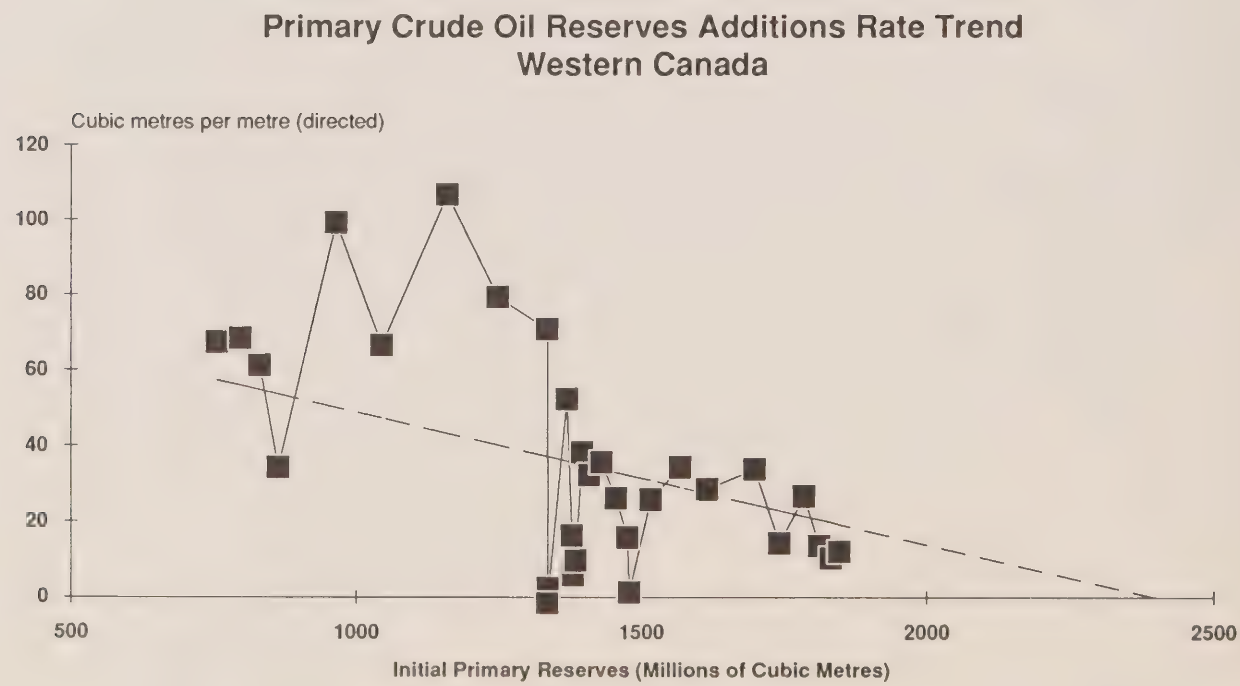


Table 7-4

Input Costs for Crude Oil

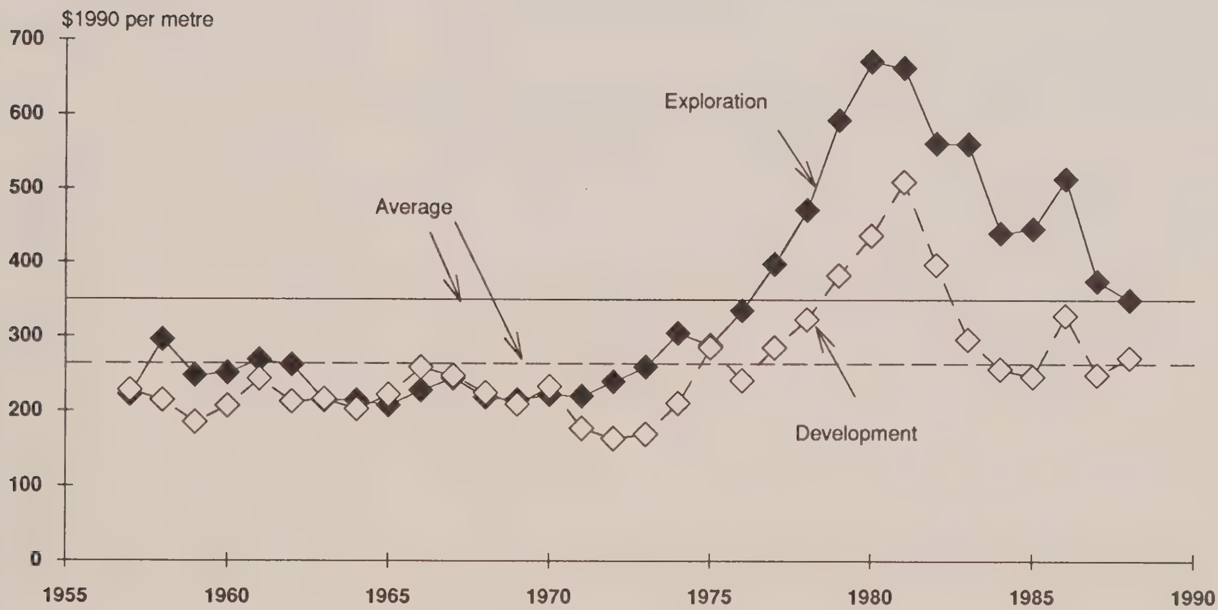
(Control Case)

Exploratory Drilling (1990 $C /m)	350.00
Development Drilling (1990 $C /m)	265.00
Field Equipment (1990 $C 1000/well)	260.00
Fixed Costs per year (1990 $C 1000/well)	34.00
Variable Cost (1990 $C /cubic metre of fluid pr	2.40

Note: Geological and geophysical costs are assumed to be 30 percent of exploration and development costs in both cases.

Figure 7-6

Historical Drilling Cost Per Metre in the WCSB



assumed projection of finding rates. While we recognize that supply costs could be somewhat higher or lower than those we have projected, we have not conducted a sensitivity analysis to assess the impact of alternative projections of costs on conventional crude oil supply, as their impact was thought to be less significant than the impact of variations in crude oil prices and we were constrained in the number of cases which could be presented in this report.

Our estimated supply costs for increments of reserves additions are given in Appendix Table A7-5. These estimates fall between the low and high case estimates in the 1988 Report, tending toward the high case in the early years. The supply cost of marginal production was increased by 10 percent to allow for royalty payments, which was not done in the 1988 projection. This, and the fact that crude oil reserves additions since the 1988 Report have been below the previous trend, results in a small downward adjustment to the additions rate trend line. The input costs underlying our current supply cost projection are similar to those used for the 1988 low case.

For conventional light crude oil in frontier regions, we have developed supply cost estimates only for certain discovered fields in the East Coast Offshore and Mackenzie Delta and Beaufort Sea regions. These estimates have been used to assess the likely range of supply costs for other frontier projects which may contribute to supply over the projection period. Supply costs and other data relevant to the evaluation of supply from individual frontier projects are summarized in Appendix Table A7-6. In estimating supply costs for discovered recoverable resources in the East Coast Offshore we used estimates of cost data for approved development plans, provided by operators of the Hibernia and Cohasset/Panuke fields, to estimate a likely range of supply costs for future developments. The supply costs for these fields ranged from $ 110 per cubic metre ($US 15/bbl) for development of the small Cohasset/Panuke field where production facilities are located on a jack-up drilling unit and production is stored on a moored storage tanker, to $ 200 per cubic metre ($US 25/bbl) for development of the large Hibernia field. The Hibernia field is to be developed using a ground-based production platform with storage facilities included in the structure. (The $ 200 per cubic metre estimate does not include the effects of any grants or fiscal arrangements for this project.) Both the Cohasset/Panuke and Hibernia facilities will require shuttle tankers to transport the production to shore. From the divergence in costs for these two projects, it is clear that the nature of the development plan can have a major impact on supply costs.

Given the size of the fields in the discovered recoverable resource category, we have assumed that they will be developed with floating storage tankers rather than massive ground-based production platforms. This is reflected in the supply cost estimate for the Terra Nova field of $ 140 per cubic metre ($US 19/bbl). Other East Coast fields included in our control case have supply costs between those estimated for Terra Nova and Hibernia.

Discovered recoverable resources in the Beaufort Sea - Mackenzie Delta are also a potential supply source. We have evaluated the supply costs of the Amauligak field in the Beaufort Sea and of a group of several smaller fields in the Mackenzie Delta-Beaufort Sea area that could possibly be developed after a transportation system is in place. Amauligak has a supply cost of $ 80 per cubic metre and a transportation charge of $ 104 per cubic metre to Edmonton, if developed by itself. The transportation cost could be lowered somewhat if the pipeline to Alberta could be used for the transportation of liquids associated with the production of natural gas. The overall transportation cost includes two pipeline charges, of which the transportation cost from Amauligak to Zama Lake in Alberta is the most important at $ 101 per cubic metre. The transportation charge from Zama Lake to Edmonton is only $ 3 per cubic metre. The total supply cost at Edmonton is $ 184 per cubic metre ($US 23/bbl). The smaller fields have a supply cost of $ 140 per cubic metre and a transportation charge of $ 66 per cubic metre for a total supply cost of $ 206 per cubic metre ($US 26/bbl), assuming development in conjunction with Amauligak.

Bitumen and Synthetic Crude Oil

The supply costs of bitumen vary from project to project, depending on reservoir characteristics and the viscosity of the bitumen. The supply costs of the projects considered in our projection generally fall in a range of $ 65 to $ 90 per cubic metre at the plant gate. Some projects that can produce bitumen under primary recovery without steam injection, and some very cost effective steam floods, fall in the lower end of this range. However, most projects considered are toward the high end of the range.

Bitumen can be sold as is or upgraded to synthetic crude oil. The market for bitumen can be

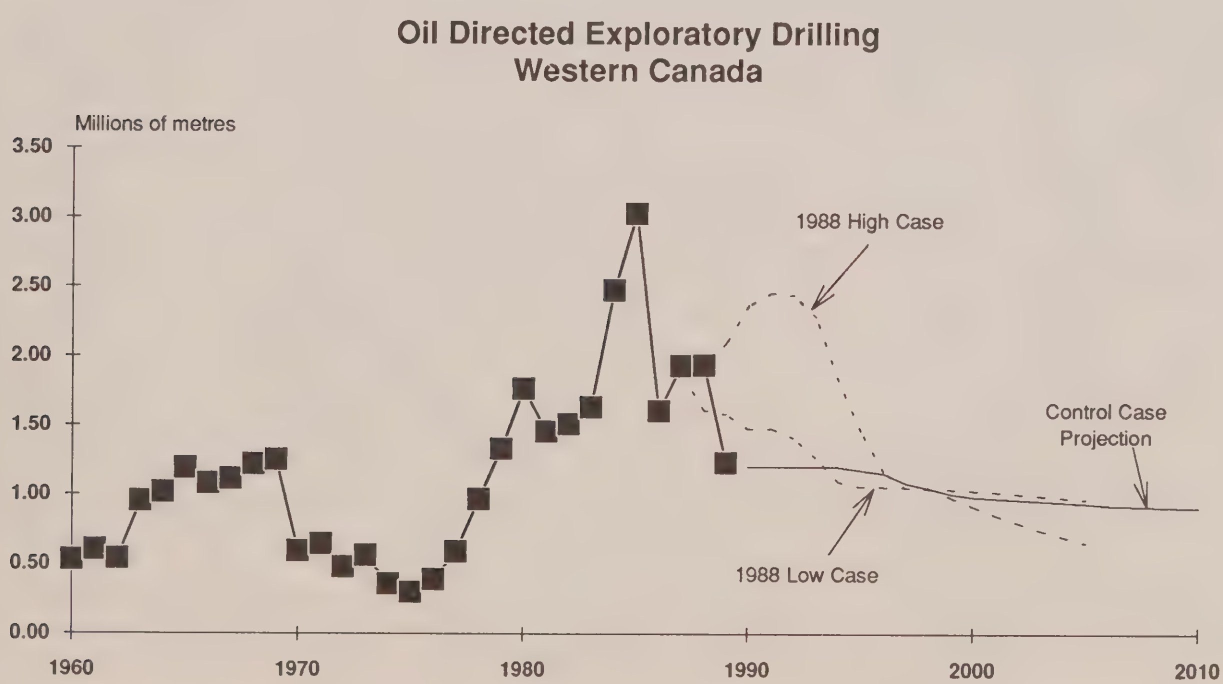
rather volatile, whereas synthetic crude oil is generally much easier to market. Uncertainty with regard to the market for bitumen can thus be alleviated by upgrading the bitumen to a synthetic crude oil. This is only profitable if the cost of upgrading does not exceed the price differential between bitumen and synthetic crude oil. This differential is discussed in more detail in section 7.3.6.1. Bitumen supply costs, the cost of upgrading, and the supply costs of integrated mining plants are summarized in Appendix Table A7-7, along with other data relevant to the evaluation of these projects. Our estimates show upgrading costs in the range of \$ 82 - \$ 96 per cubic metre and assume that bitumen can be delivered to the upgrader at \$ 87 per cubic metre. This results in supply costs for upgraded bitumen from in situ projects in the \$ 169 - \$ 183 per cubic metre range, somewhat lower than an integrated mining plant operation which has an estimated supply cost of about \$ 198 per cubic metre. We do not consider this difference in estimates of supply costs to be significant, given the assumptions inherent in our analysis and the scope for technological change over the projection period, and anticipate that there will be more or less simultaneous development of integrated mining plants and upgraders for in situ production given the projected growth in prices over the period.

7.2.1.4 Projected Oil Directed Activity

We assess the motivation for producers to bring on new crude oil supplies through drilling activity by first comparing projected incremental supply costs with wellhead crude prices in Western Canada. Activity is initially estimated at a level required to maintain an equilibrium between marginal supply costs and wellhead prices, with some constraints on the rate of change in activity. This initial estimate is adjusted judgmentally to reflect our knowledge of industry plans in the near to medium term. Supply costs and wellhead prices in Western Canada were approximately in equilibrium in 1990. Oil directed activity is projected so as to maintain an approximate equilibrium between costs and crude oil prices over the projection period and declines very slowly from current levels, as shown in Figure 7-7. This projected drilling activity generally approximates the low case estimate of the September 1988 Report. Our control case prices are somewhat higher than the 1988 low case, but so also are supply costs, largely because of the inclusion of the 10 percent royalty.

Drilling statistics are not subdivided according to light and heavy crude oil categories. Our projections of light and heavy additions are correlated with total oil directed activity.

Figure 7-7



7.2.2 Reserves Additions of Conventional Light Crude Oil

We first discuss reserves additions in the WCSB, which are comprised of reserves additions from other discovered resources and undiscovered resources, and then reserves additions in the frontier regions.

7.2.2.1 Reserves Additions from Other Discovered Recoverable Resources in the WCSB

Reserves additions in this category include those arising from improved recovery methods, including infill drilling, technological improvements such as horizontal drilling, waterflood projects and miscible flood projects in established pools.

Reserves additions resulting from future waterfloods in currently established pools in Western Canada were analyzed in greater detail than for the 1988 Report. All of the existing waterfloods in Alberta were grouped by producing formation and these projects were analyzed in detail to identify common reservoir parameters and pool characteristics. A set of screening criteria was developed from this analysis and used to evaluate potential waterflood development for all pools or pool areas under primary depletion in Alberta. A selected number of pools which were determined to be waterflood candidates were then analyzed to determine their economic viability under the control and sensitivity cases crude oil price scenarios. All of the larger pools in our sample, representing 60 percent of the remaining waterflood reserves potential, were then assessed using guidelines developed on the basis of the analysis of the selected pools to determine to what extent the potential could become economic during the projection period. These results were then extrapolated to the remaining smaller candidate pools in Alberta, and also to the reserves under primary depletion in B.C. and Saskatchewan, to estimate the total waterflood reserves additions for established pools to be included in our projections.

Waterflood reserves additions from established pools total 39 million cubic metres over the projection period in the control case. As shown in Appendix Table A7-8, the additions continue at current levels of about three million cubic metres per year until 1995 and then progressively decline over the remainder of the period as the number of remaining candidate pools declines. In the low oil price sensitivity case waterflood reserves additions total only 10 million cubic metres, as there are few candidate pools that are viable at crude prices less than $US 20 per barrel. With oil prices experiencing stronger real growth in the high oil price sensitivity case, we project waterflood reserves additions totalling 53 million cubic metres.

Our analysis indicates that reserves additions from future miscible flood projects in currently established pools require a minimum price of about $US 20 per barrel to be economically viable. As shown in Appendix Table A7-8, annual reserves additions in the control case are expected to remain at a very modest level until the last half of the 1990s, when crude oil prices are projected to reach the $US 22-25 per barrel range. Over the projection period, additions total 43 million cubic metres in the control case. In the low price sensitivity case, the projected price does not reach the required minimum and consequently only additions related to projects that operators have indicated will proceed have been included. In this case reserves additions total only 5 million cubic metres. In the high price sensitivity case additions total 60 million cubic metres. Our projected reserves additions of light crude oil resulting from the future application of miscible flood techniques are slightly lower than those in our 1988 Report. This is a result of projects being initiated in the 1987-89 time period and recent revisions to the Alberta royalty regime for miscible flood projects, which are expected to have a negative impact on the economic viability of these projects.

Application of chemical flooding in currently established pools requires a minimum price of approximately $US 30 per barrel. The oil price does not reach this level in the control case nor in the low oil price sensitivity case. Hence reserves additions from this source are projected only for the high price sensitivity case, where the oil prices reach $US 30 per barrel late in the projection projects period. For the high case, reserves additions by chemical flooding amount to only 5 million cubic metres over the projection period.

Reserves additions resulting from infill drilling in currently established pools and the application of technological improvements, such as horizontal drilling, are expected to occur over the projection period. For example, we anticipate that horizontal drilling will be progressively applied and, particularly in certain types of reservoirs, could lead to substantial reserves additions. On the basis of our analysis and consultations, we have judgmentally estimated additions to account for these factors. Our control case estimates of reserves

additions from the future application of improved recovery techniques in currently established pools total 129 million cubic metres over the projection period (Appendix Table A7-8). However, we recognize that there is much uncertainty regarding the impact of future technological change.

7.2.2.2 *Reserves Additions from Undiscovered Recoverable Resources in the WCSB*

Our projections of reserves additions in Western Canada from undiscovered recoverable resources are derived using our estimates of oil directed drilling (Figure 7-7), which have been discussed in section 7.2.1.4, and our projection of the additions rates per unit of drilling (Figure 7-5).

Reserves additions of conventional light crude oil in Western Canada resulting from the projected drilling activity are estimated to total 242 million cubic metres over the projection period in the control case (Appendix Table A7-8) and to amount to about 75 million and 350 million cubic metres in the low and high oil price sensitivity cases, respectively. Annual levels of these additions tend to decline over the projection period as the resource becomes more depleted and the prospects for new discoveries diminish. Estimated improved recovery additions associated with the new discoveries are included in this projection, as shown in Figure 7-8.

Projected reserves additions of conventional light crude oil in Western Canada are approximately the same as the low case in the 1988 Report (Figure 7-9).

7.2.2.3 *Reserves Additions from Frontier Areas*

In addition to the established reserves currently recognized by the Board, Canada's frontier regions have significant potential for reserves additions. These arise from both the development of discovered resources which are not currently considered to be economically viable, and from new discoveries and extensions.

Projected reserves additions for the East Coast Offshore region over the projection period are relatively small despite the large resource in this region, because supply costs are high compared to projected crude oil prices. In the control case, we expect reserves additions of nearly 150 million cubic metres in this region. Approximately 120 million cubic metres of this is expected to come

Figure 7-8

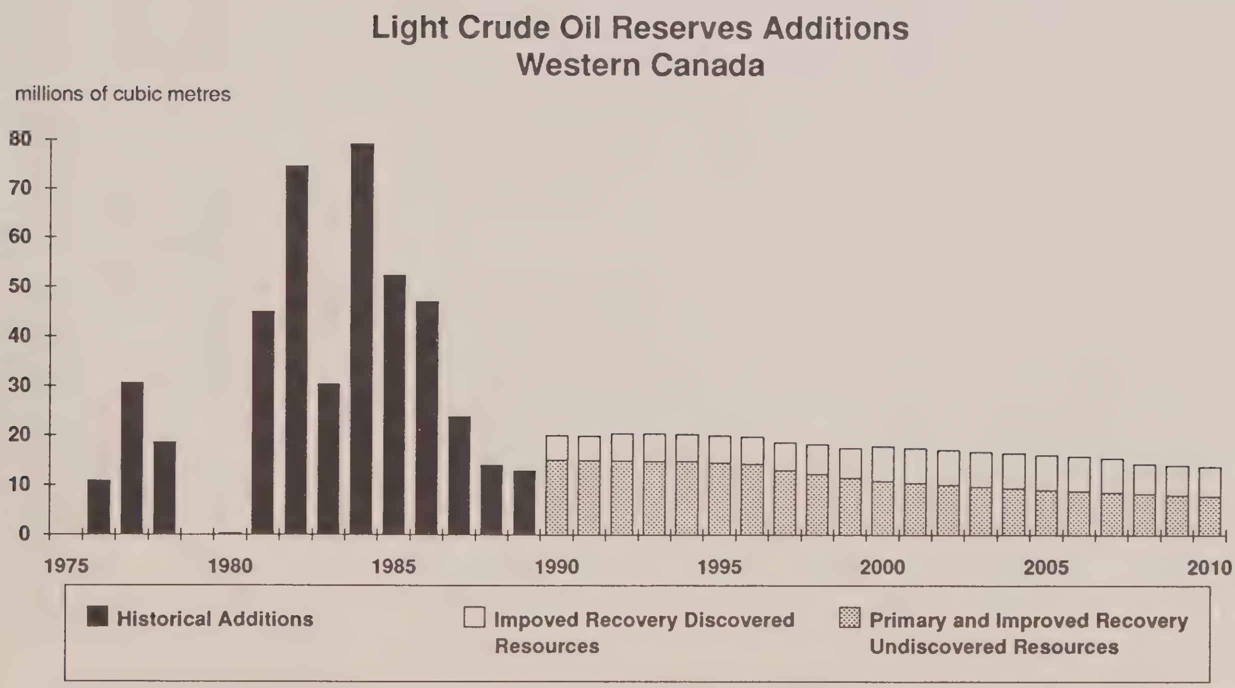
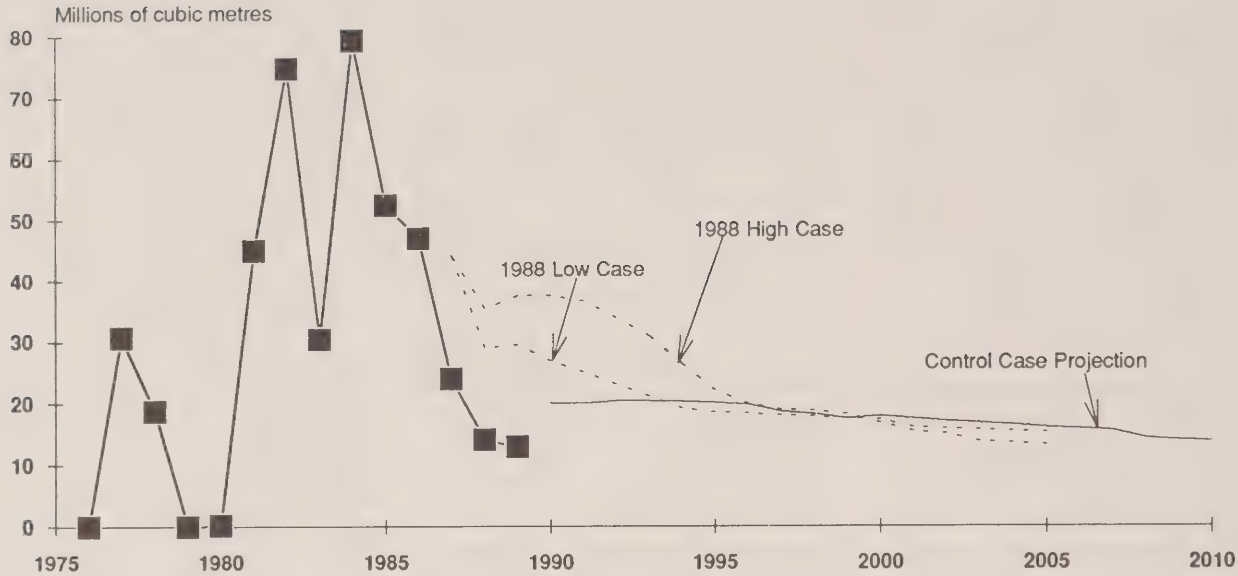


Figure 7-9

Comparison of Light Crude Reserves Additions
Western Canada



from the other discovered recoverable resources category and the remainder from new discoveries. In the low oil price sensitivity case we expect reserves additions of only 50 million cubic metres, all from the other discovered recoverable resources category. In the high oil price sensitivity case we expect reserves additions of 210 million cubic metres.

In the control case we expect reserves additions of 90 million cubic metres in the Mackenzie Delta-Beaufort Sea region over the projection period and essentially all of these reserves additions are related to the inclusion of additional discovered recoverable resources in the established reserves category. In the low case we do not expect any significant reserves additions from this region, but in the high case we project 135 million cubic metres of reserves additions.

In both the Mackenzie Delta-Beaufort Sea and East Coast offshore regions there is also the potential for sizeable discoveries to be made over the projection period. In the control case we have included primarily reserves additions related to those discovered resources which are expected to become economically viable over the projection period. To the extent that other significant discoveries occur over the period, and are economically viable given our price outlook, our reserves additions projection will be understated.

Certain of the other frontier areas may have some activity during the projection period, while some (e.g. the Arctic Islands) are likely too remote for significant exploration and development under our expected crude oil price scenario. However, exploratory results in all of these areas are very uncertain and have therefore not been included in our control case projection.

7.2.3 Reserves Additions of Conventional Heavy Crude Oil

Conventional heavy crude reserves additions are obtained from other discovered recoverable resources and undiscovered recoverable resources in the WCSB.

7.2.3.1 Reserves Additions from Other Discovered Recoverable Resources of the WCSB

Reserves additions in this category include those arising from improved recovery methods, including infill drilling, technological improvements such as horizontal drilling, waterflood projects and thermal projects in established pools.

As for light oil, we analyzed reserves additions of heavy oil resulting from the application of waterflooding techniques in

currently established pools in greater detail than in the 1988 Report. For the control case, waterflood reserves additions total 25 million cubic metres. The majority of the additions are projected to occur in the first half of the 1990s, with a decline in additions beginning in 1997. Rising oil prices in the high oil price sensitivity case have little impact on waterflood reserves additions as there are only a limited number of established conventional heavy oil pools that are viable waterflood candidates. We project 28 million cubic metres of waterflood reserves additions in the high price case. In the low oil price sensitivity case, we project only 7 million cubic metres of waterflood reserves additions.

Reserves additions resulting from the future application of thermal techniques in currently established pools are projected to commence when oil prices reach $US 25 per barrel, approximately in 2005 in the control case and in 1996 in the high oil price sensitivity case. Additions total 10 and 31 million cubic metres in the control and high price cases, respectively. There are no additions in the low oil price sensitivity case because the projected price is insufficient to provide an adequate return on these projects.

As was the case for conventional light crude, on the basis of our analysis and consultations we have judgmentally estimated reserves additions of heavy crude oil arising from infill drilling and technological improvements, such as horizontal drilling. We anticipate that the progressive application of horizontal drilling technology could have a substantial impact on heavy oil reserves additions, but at this time the extent of its application is difficult to assess.

Our control case estimates of reserves additions from the future application of improved recovery techniques in currently established pools total 65 million cubic metres over the projection period (Appendix Table A7-9).

7.2.3.2 Reserves Additions from Undiscovered Recoverable Resources of the WCSB

Reserves additions of conventional heavy crude oil from undiscovered recoverable resources in the WCSB are estimated to total 229 million cubic metres over the projection period (see Appendix Table A7-9) and amount to about 70 million and 270 million cubic metres in the low and high oil price sensitivity cases, respectively. Annual levels of these additions, for both primary and improved oil recovery, decline gradually (Figure 7-10).

Figure 7-10

Heavy Crude Oil Reserves Additions Western Canada

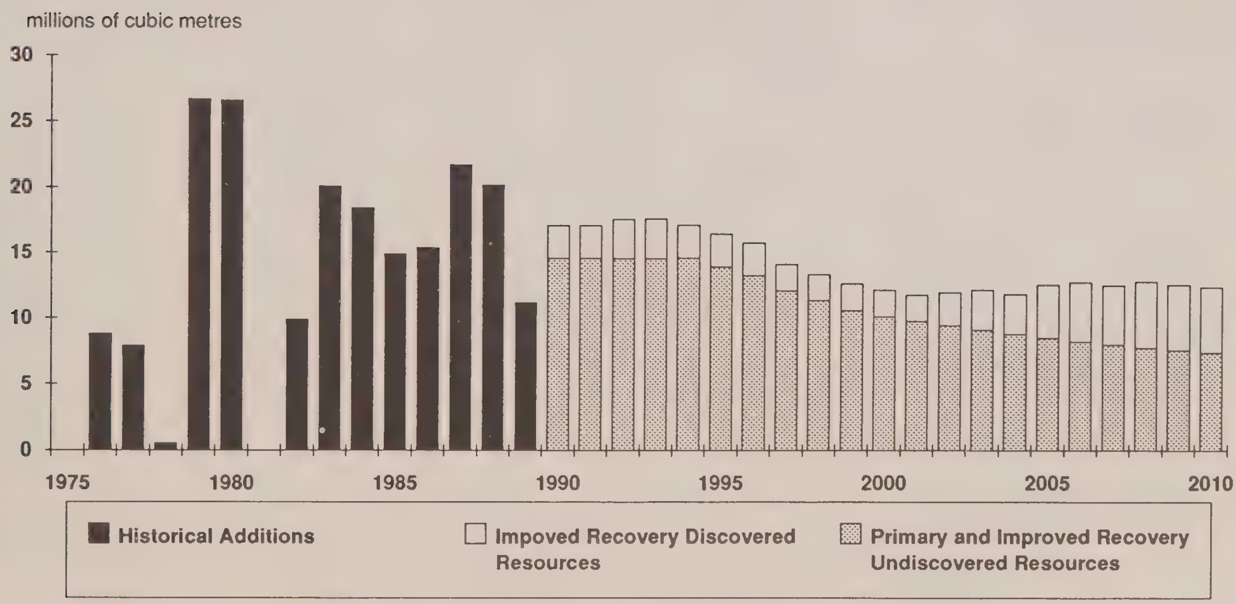
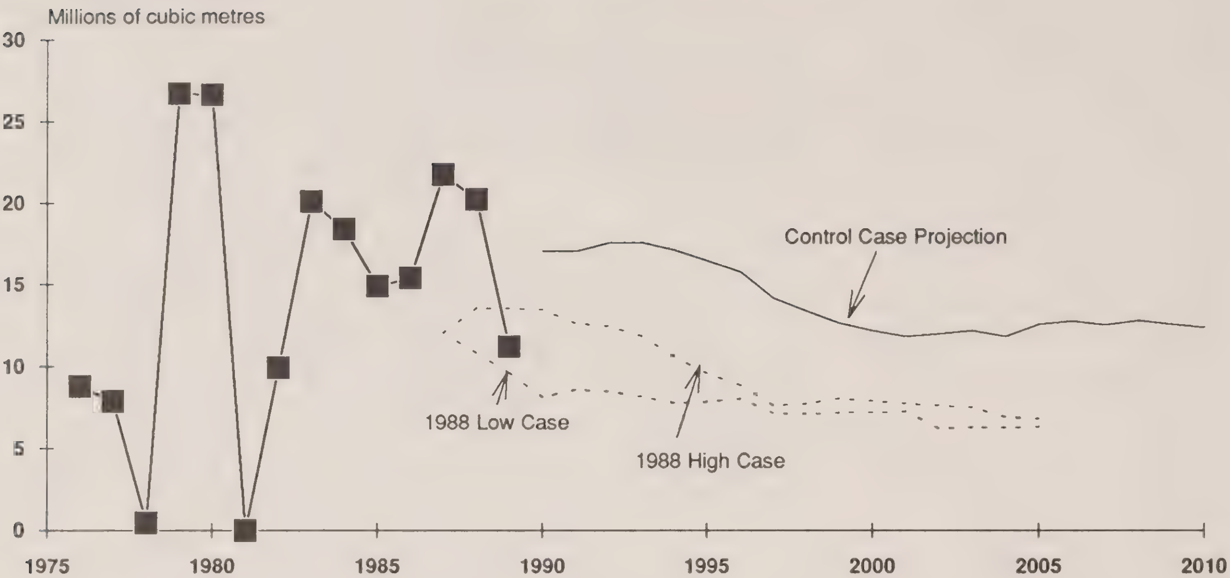


Figure 7-11

Comparison of Heavy Crude Reserves Additions Western Canada



Projected reserves additions of conventional heavy crude oil in Western Canada are larger than we estimated in the 1988 Report because of our increased estimate of the remaining potential and because we have assumed that technological progress such as horizontal drilling will have a greater impact than previously projected (Figure 7-11).

7.2.4 Reserves Additions of Bitumen

Reserves additions of bitumen will be required at existing mining operations and in situ operations to replace established reserves as they are depleted. There will also be reserves additions associated with the development of new mining and in situ projects.

7.2.4.1 Reserves Additions from Mining Plants

In order to maintain production from the Suncor operation at projected levels through 2010, about 30 million cubic metres of reserves additions will be required in the late 1990s, following the depletion of remaining bitumen reserves at the currently active Suncor lease. At Syncrude, the remaining reserves are sufficient to keep the project operating at expected levels of production for many years beyond the projection period.

Reserves additions of a further 230 million cubic metres of bitumen are anticipated during the projection period in the control case, arising from the start-up of operations of two new bitumen mining plants. These plants are assumed to be constructed four to five years apart because of the scale of the projects and the specialized workforce involved. Reserves additions of 345 million cubic metres are projected in the high case as one additional mining plant is included in the projection. A project similar to OSLO, operating for 25 years, requires about 115 million cubic metres of reserves. In the low oil price sensitivity case, only the 30 million cubic metres of reserves additions from Suncor's development of a new lease is expected.

7.2.4.2 Reserves Additions from In Situ Recovery Projects

Currently, in situ bitumen is produced at a rate of about one thousand cubic metres per day per five million cubic metres of initial reserves. Assuming this relationship between production and reserves is maintained in the future, it is expected that reserves of about 260 million cubic metres will be added from new in situ projects during the projection period in the control case. In the low and high oil price sensitivity cases, reserves additions of about 25 million and 360 million cubic metres, respectively, are projected.

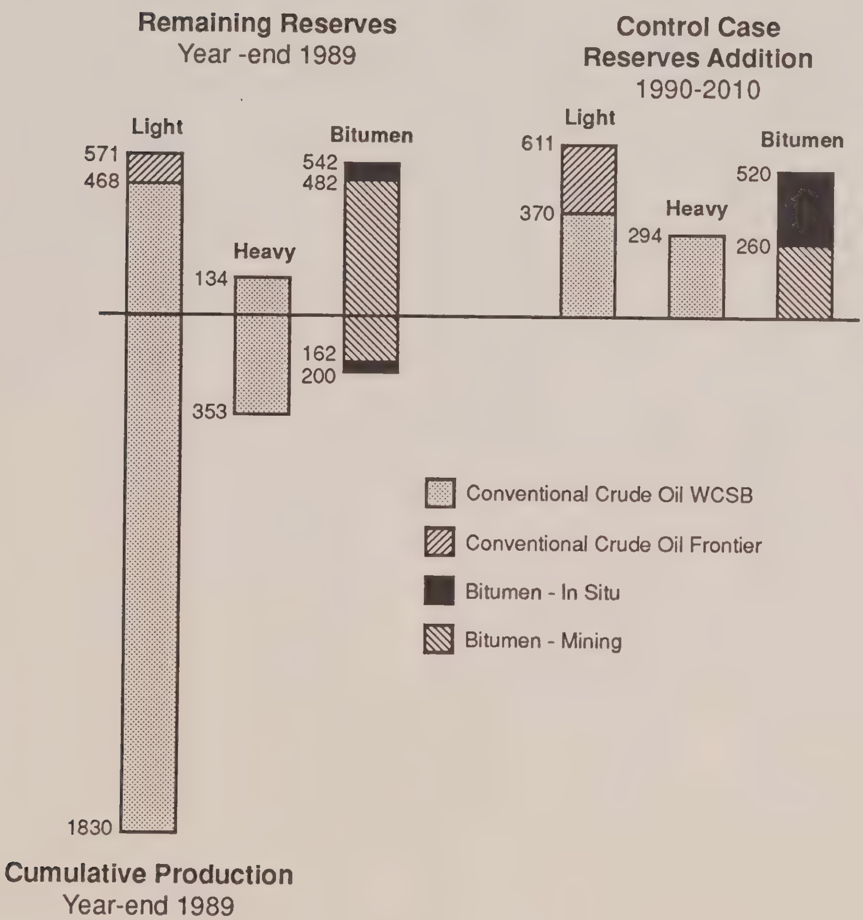
7.2.5 Summary of Reserves Additions

Estimated total reserves additions of conventional light and heavy crude oil and bitumen over the projection period for the control case are compared with remaining established reserves and cumulative production at year-end 1989 in Figure 7-12. Conventional light crude oil additions total 611 million cubic metres, which is slightly more than the remaining established reserves of 571 million cubic metres. For conventional heavy crude oil, additions total 294 million cubic metres, which is more than double the 134 million cubic metres of remaining established reserves. Bitumen reserves additions total 520 million cubic metres over the projection period, slightly below the remaining established reserves of 542 million cubic metres.

Figure 7-12

Remaining Reserves and Reserves Additions

(millions of cubic metres)

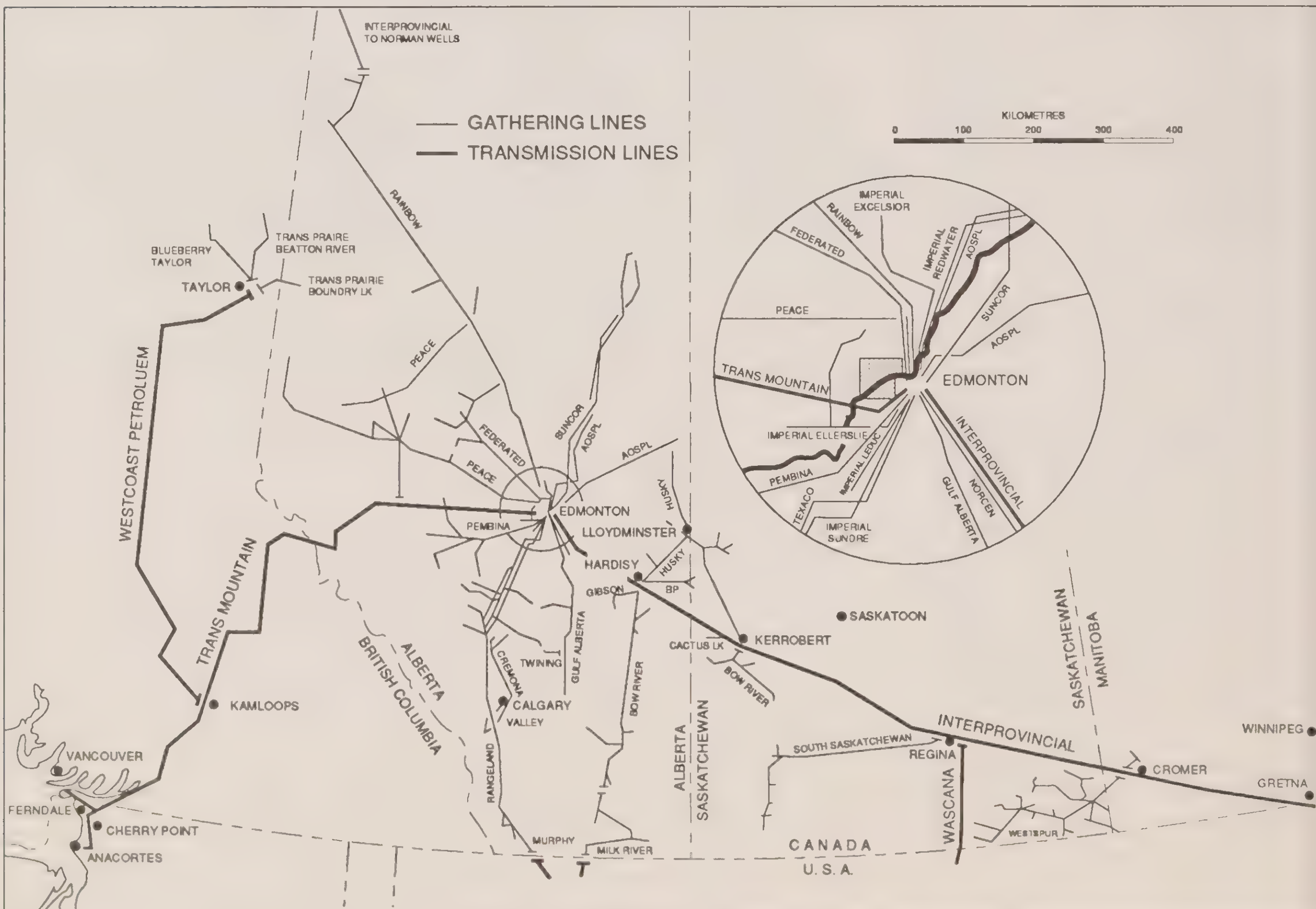


7.3 Projected Supply

In the preceding sections of this chapter we discussed our current estimates of established reserves and our projections of reserves additions. In this section we describe our projections of supply from established reserves and reserves additions for conventional light and heavy crude oil, synthetic crude oil from integrated mining plants, crude bitumen, pentanes plus and synthetic crude oil from upgrading. We then aggregate these supply components to obtain projections of light and heavy crude oil supply and, finally, a projection of total crude oil and equivalent supply.

In developing our projections of productive capacity from established reserves, we evaluated approximately 400 of Canada's major oil pools, or more than 90 percent of established reserves, on an individual basis. This involved the examination of well and pool performance data, taking into consideration trends in oil, gas and water production, as well as other pertinent parameters. In addition to analyzing pool performance data, we incorporated into our analysis the results of more detailed studies conducted by Board staff and information from external sources where available. Discussions with operators of major pools were held to review reserves and productive capacity data. The effects of proposed drilling programs and improved recovery schemes were only included in the projection of productive capacity for established reserves if it appeared certain at the time of evaluation that these projects would be undertaken. Projects not yet implemented are accounted for in our projection of

Figure 7-13
Major Crude Oil Gathering Lines



productive capacity from reserves additions. The remaining pools, which represent less than 10 percent of established reserves, were grouped into several categories and evaluated on an aggregate basis.

Figure 7-13 shows the location of the major gathering and trunk pipelines which transport crude oil from producing fields to refining centres. Our projections of productive capacity from established reserves are arranged by crude type, province and major pipeline system.

Productive capacity projections for some categories of reserves additions, in particular reserves additions for conventional light and heavy crude from new discoveries in the WCSB, are estimated using a standard normalized production profile formulated on the basis of historical data. For other categories of reserves additions our estimates of productive capacity are based on project-specific analysis conducted by Board staff or based on published information or consultations with project operators and other industry representatives.

7.3.1 Conventional Light Crude Oil Supply

Projections of conventional light crude oil supply are comprised of supply from established reserves and reserves additions in both the WCSB and frontier regions.

7.3.1.1 Supply from Established Reserves

The total supply from currently established reserves of conventional light crude oil in **Western Canada** is projected to decline from 142 thousand cubic metres per day in 1990 to 15 thousand cubic metres per day in the year 2010 (see Appendix Table A7-10).

In the early to mid 1980s, the larger reef pools which constituted a significant portion of the total conventional light crude oil supply did not yet exhibit severe production declines. Discoveries in Alberta in the Rainbow area and in the Peace River Arch area, adjacent to the Peace River and Rainbow Pipeline systems, and major improvements in the recovery mechanisms in the Beaverhill Lake reservoirs and the larger Gilwood pools in north central Alberta and the Norman Wells field in the Northwest Territories, all served to buoy up productive capacity.

In recent years, many of the large reef pools in Alberta have been exhibiting marked production declines. In contrast, the Nisku pools in the West Pembina area of Alberta have generally performed better than expected, and currently contribute 14 000 cubic metres per day, or 12 percent of Alberta's light crude oil supply. However, production from these pools is now also beginning to decline and is anticipated to decline steeply in the near to medium term. As a result, productive capacity from currently established reserves in Alberta is expected to decline at about 14 percent per year over the projection period.

In Saskatchewan the decline in productive capacity from currently established reserves averages 12 percent per year over the projection period. Recent discoveries in the Macoun and Minton areas have partially offset the decline in productive capacity for southeastern Saskatchewan light crude oil.

British Columbia has the slowest decline in production from currently established reserves, at an average annual decline rate of about 10 percent over the projection period. The recent discovery and development of the Brassey field moderates the production decline.

This analysis of productive capacity of light crude oil from currently established reserves resulted in an overall average annual decline rate of 13 percent and an increase in the Reserves Life Index (RLI) from about 9 to 16 over the projection period (Appendix Table A7-10). Although some increase in the RLI is anticipated, as lower productivity pools contribute a greater proportion of production in the longer term, we considered a more moderate increase in RLI to be likely in view of past trends which show that activities such as infill drilling and well workovers tend to accelerate pool production. As a consequence, we judgmentally adjusted the crude oil productive capacity for light crude oil such that the RLI increases from 9 to 12 over the projection period. This reduces the average decline for production from currently established reserves to about 11 percent from 13 percent. This adjustment incorporates only the production acceleration aspects of infill drilling and well workovers; the reserves additions and related productive capacity associated with these activities are accounted for separately.

Our estimate of productive capacity from established reserves in Alberta is somewhat lower than that of the ERCB, primarily because we have somewhat different assessments of established reserves based on pool performance analysis in certain areas of the province.

We do not consider supply from established reserves to be very sensitive to the range of oil prices used in our analysis and have not adjusted these projections for the high and low oil price sensitivity cases.

The established reserves in the East Coast Offshore **frontier regions** are expected to make a considerable contribution to supply over the projection period. The Cohasset/Panuke fields offshore Nova Scotia are expected to be brought on production on a seasonal basis in 1992, with an average production rate of 2.6 thousand cubic metres per day. The Hibernia field offshore Newfoundland is expected to come onstream in 1996, with production of 17.5 thousand cubic metres per day. Development activity in these fields is currently underway and projected production rates are in accordance with the plans of the operators.

In other frontier regions, we expect Bent Horn in the Arctic Islands to continue producing limited quantities of crude oil for summer tanker shipment out of the Arctic. A considerable amount of uncertainty exists with respect to the estimate of reserves for the Bent Horn field. We have assumed that production will continue through 2006.

The productive capacity projections for the frontier regions for the control case are provided in Appendix Table A7-11. We anticipate that the projection of supply from established reserves would not change much in the high and low price cases.

7.3.1.2 Supply from Reserves Additions

Supply from reserves additions of conventional light crude oil in **Western Canada** is projected to reach about 45 thousand cubic metres per day by the end of the projection period. Infill drilling, waterfloods and miscible flood projects related to discovered resources contribute about 17 thousand cubic metres per day to this total and undiscovered resources about 28 thousand cubic metres per day (see Appendix Table A7-8). This is insufficient to offset the decline in productive capacity from established pools. In the low oil price sensitivity case, supply in 2010 from reserves additions amounts to about 11 thousand cubic metres per day and, in the high oil price sensitivity case, about 61 thousand cubic metres per day.

The estimated supply from reserves additions by province is detailed in Appendix Table A7-12. For this disaggregation, we assumed that supply from each category of reserves additions is proportional to the remaining potential of that category in each province, as shown in Appendix Table A7-2. While this assumption may not be strictly accurate, we believe that it provides a reasonable basis for the projection of productive capacity from reserves additions on a provincial basis.

In the **frontier regions**, Terra Nova is expected to commence production in 1998, adding approximately 14 thousand cubic metres per day to supply. Further East Coast offshore development is expected, involving other pools with somewhat higher supply costs. We anticipate that the total supply from the East Coast region will reach a level of just over 40 thousand cubic metres per day in the year 2003, of which 23 thousand cubic metres per day are estimated to come from reserves additions. We expect productive capacity to subsequently stabilize at a level of about 38 thousand cubic metres per day for the remainder of the projection period. Appendix Table A7-11 provides further detail on projected frontier supply. In the low oil price sensitivity case, production reaches 31 thousand cubic metres per day in 1999, with production decline starting in 2005. In the high oil price sensitivity case, production reaches a level of 46 thousand cubic metres per day in 2004 and remains at that level over the remainder of the projection period.

Production from the Beaufort Sea does not occur until 2004 in the control case, which is coincident with the projected development of gas production in the Mackenzie Delta. While the oil development and the pipeline associated with it would facilitate the transportation of NGL, the concurrent construction of oil and gas pipelines from the Mackenzie Delta could lead to some logistical difficulties. To avoid such problems, oil and gas development may be staggered. With pipeline construction beginning in 2002, we expect crude oil production to commence in 2004 at an average rate of 12 thousand cubic metres per day. We expect this production rate to be maintained beyond 2010 through the development of small pools in the Mackenzie Delta-Beaufort Sea area. We do not expect any crude oil production from this area in the low oil price sensitivity case. In the high oil price sensitivity case, crude oil production commences in 2000, and peaks at 19 thousand cubic metres per day in 2003, as additional pools come on stream earlier than in the control case.

7.3.2 Conventional Heavy Crude Oil Supply

Our projections of conventional heavy crude oil supply are comprised of supply from established reserves and reserves additions in the WCSB.

7.3.2.1 Supply from Established Reserves

The total supply from currently established reserves of conven-

tional heavy crude oil is projected to decline from 46 thousand cubic metres per day in 1989 to about two thousand cubic metres per day in the year 2010 (Appendix Table 7-13).

Over the period since our last report in 1988, the supply of conventional heavy crude oil has increased by about six thousand cubic metres per day. Although this increase is higher than was anticipated, it is consistent with the trend that has seen the supply of conventional heavy crude oil increasing throughout the decade of the 1980s. This increase can be attributed in large part to the factors outlined below:

- an overall increase in the number of operating heavy oil wells resulting primarily from new discoveries, pool extensions and infill drilling;
- reductions in operating costs which have improved the profitability of heavy oil production;
- overall growth in fluid-handling capacity, particularly in the Grand Forks area of southeast Alberta;
- technological innovations, including the recent advent of horizontal drilling; and
- the implementation of a number of improved recovery projects, the majority of which are waterflood projects.

We expect that Alberta and Saskatchewan will continue to contribute approximately equally to heavy crude oil supply and that the RLI for established reserves will decline from about 8 to 6 over the projection period.

7.3.2.2 Supply from Reserves Additions

Estimated supply from reserves additions of conventional heavy crude oil in the WCSB is projected to increase to about 36 thousand cubic metres per day over the projection period in the control case. As was the case for conventional light crude, this is insufficient to offset the decline in productive capacity from established pools. Infill drilling, waterfloods and thermal recovery projects related to other discovered recoverable resources contribute about 10 thousand cubic metres per day to this total and undiscovered recoverable resources about 26 thousand cubic metres (see Appendix Table A7-9). In the low and high oil price sensitivity cases, supply from reserves additions in 2010 amounts to about 8 thousand and 43 thousand cubic metres per day, respectively.

The estimated supply from reserves additions by province is provided in Appendix Table A7-12. As for light crude, we assumed that supply from each category of reserves additions is proportional to the potential of that category in each province, as shown in Appendix Table A7-2.

7.3.3 Synthetic Crude Oil Supply from Integrated Mining Plants

Commercial production of synthetic crude from Western Canada's bitumen deposits began in 1967 when an integrated mining and upgrading plant, owned and operated by Suncor Inc., commenced producing synthetic crude oil. A second integrated plant, operated by Syncrude Canada Ltd., became operational in 1978. The current level of synthetic crude oil production from these two plants is about 33 thousand cubic metres per day.

In our projection we consider four projects, which in total would add about 30 thousand cubic metres per day to the synthetic crude oil supply. Our projections include the expansion of each of the two existing plants and two new plants. Expansion or "debottlenecking" at existing plants is assumed during the mid 1990s, adding about 5700 cubic metres of synthetic crude oil by the end of the projection period.

The OSLO project, with expected peak production of about 13 thousand cubic metres per day, is anticipated to commence production in 2005. This start-up date is based on our estimate of the costs of the project in relation to our projected crude oil price path. The announced target date for startup of the project is 1997, and although delays associated with the development of this project now seem inevitable, fiscal assistance by one or both levels of government or an alternative view of oil prices by the project sponsors could cause this project to proceed at an earlier date than provided for in our projections. Also included in our control case synthetic crude oil projection is another mining project, similar in size to the OSLO project, with production beginning in 2009.

In the control case synthetic crude production from mined bitumen increases to about 59 thousand cubic metres per day by the end of the projection period. In the low oil price sensitivity case, it is assumed that only the existing Suncor and Syncrude operations are expanded and production is expected to be 38 thousand cubic metres per day

in 2010. For the high oil price sensitivity case, the timing of the two new projects is advanced to 1998 and 2005 as compared to 2005 and 2009 in the control case, and a third mining project is scheduled near the end of the projection period. In the high oil price sensitivity case, synthetic crude production reaches 74 thousand cubic metres per day by the end of the projection period.

7.3.4 Crude Bitumen Supply

During the 1970s, bitumen produced from in situ projects started to contribute to supply and in the mid-1980s this development accelerated. However, commercial in situ recovery projects are still exploiting only a small part of Canada's bitumen deposits, and cumulative production from these projects, and from the many experimental projects that test recovery techniques before commercial projects are considered, was only 38 million cubic metres as of year-end, 1989. Current production levels are some 20 thousand cubic metres per day.

Bitumen production is expected from existing in situ recovery projects in the Cold Lake, Peace River and Athabasca deposits and from new projects initiated over the projection period. The scheduling of production from new or expanded projects was based on supply cost estimates for typical bitumen projects in each of the bitumen producing areas and on bitumen field prices developed using the light crude/heavy crude price differentials discussed in section 7.3.6.1. The expansions of existing operation and new projects which are included in this projection are generally projects which have been identified as potential sources of future bitumen supply but have not yet been initiated due to inadequate price levels. Projects were scheduled to commence production approximately three years after the bitumen field price reached the estimated supply costs for the particular project under consideration. This delay in commencement of production is intended to account for the general reluctance of producers to invest in projects of this nature without some assurance that price levels necessary to ensure their profitability are sustained for a reasonable period of time.

The supply of bitumen increases gradually in the early years of the projection period and reaches a level of about 73 thousand cubic metres per day by 2010 (Appendix Table A7-14). For the low oil price sensitivity case, bitumen supply is maintained, primarily from currently operating projects, at about the current production level until near the end of the projection period when prices are high enough to prompt modest expansion. In the high oil price sensitivity case, bitumen supply increases more rapidly than in the control case, reaching 92 thousand cubic metres per day by 2010.

7.3.5 Pentanes Plus Supply and Diluent Requirements

Pentanes plus is obtained from natural gas production but is included as a component of crude oil and equivalent supply because, like crude oil, it is used as refinery feedstock. Pentanes plus is a natural gas liquid and the basis for the projection of its supply is further discussed in Chapter 8. The projected pentanes plus supply in Appendix Table A7-14 includes volumes associated with natural gas production in the Mackenzie Delta-Beaufort Sea and the East Coast Offshore regions. Production of natural gas liquids and crude oil from the Mackenzie Delta-Beaufort Sea area will require the construction of a liquids pipeline between the Mackenzie Delta and Zama Lake in Alberta. In the event that natural gas development precedes crude oil development, advancement of construction of the crude oil pipeline between the Mackenzie Delta and the existing small diameter pipeline from Zama Lake to Norman Wells would appear to be a possible option to enable pentanes plus and other liquids associated with the gas production to be transported to markets prior to commencement of oil production from Amauligak. The remainder of the new pipeline to Zama Lake would then be constructed consistent with the timing of the oil development.

Some conventional heavy crude and all bitumen production is diluted, generally with pentanes plus, in order to reduce its viscosity to meet pipeline specifications. The pentanes plus supply and diluent requirements are identified separately in Appendix Table A7-14. The net diluent requirements can be derived by subtracting recycled diluent[1] from gross diluent requirements. In our estimates the net diluent requirement is removed from the available light crude and equivalent supply and added to the heavy crude supply. For this reason, not all of the available pentanes plus supply contributes to light crude oil supply.

1 Recycled diluent comes from upgraders and refineries in Alberta and Saskatchewan that use the heavy oil or bitumen for products or upgrading and are capable of returning the diluent to the field through special diluent pipelines.

The volume of diluent required for blending depends on whether bitumen or heavy crude oil is being used for upgrader feedstock. On average, approximately 0.43 cubic metres of diluent are required for each cubic metre of bitumen produced. Some conventional heavy crude requires little or no diluent, while heavy crude oil from the Lloydminster area requires about 0.27 cubic metres of diluent per cubic metre of production. The conventional heavy crude oil feedstock for the Co-op upgrader requires less diluent for blending than the blended bitumen which is expected to be the primary feedstock for the Bi-Provincial upgrader and future Edmonton upgraders. We assume that all of the diluent received at future upgraders will be recycled. The currently operating Co-op upgrader does not recycle diluent, but rather processes the entire feedstock.

The total supply of pentanes plus appears to be adequate to meet net diluent requirements over the projection period, but there are other uses for pentanes plus. Depending on these other requirements and given our projection of heavy crude oil and bitumen supply it could become necessary to use light crude oil, or light crude products such as naphtha, to satisfy the total diluent requirements arising from our projection. Unless "other" requirements for pentanes plus increase significantly, we do not foresee a need for alternative diluents until after 2000.

In the low oil price sensitivity case the supply of pentanes plus exceeds the requirement for diluent for the entire projection period. However, in the high oil price sensitivity case alternatives to pentanes plus will be required by the mid-1990s to meet the total diluent requirement.

7.3.6 Synthetic Crude Oil from Upgrading

The increasing levels of bitumen supply have caused concern about both the adequacy of the supply of pentanes plus for diluent and the marketability of incremental volumes of blended heavy crude oil (including both blended bitumen and blended conventional heavy crude oil). This has led to proposals for upgrading plants that would convert lower priced bitumen and/or conventional heavy crude oil to a higher value synthetic light crude oil. One such upgrader using conventional heavy crude oil as feedstock is currently being operated by Newgrade Energy Inc. at the Co-op refinery location in Regina. This refinery has shifted its feedstock requirements from conventional light crude oil to synthetic crude oil and now utilizes almost the entire output from this upgrader. Any surplus synthetic oil is sold to other refineries. Construction of a second stand alone upgrader in the Lloydminster area has commenced. This plant, the "Bi-Provincial" upgrader, is not associated with a refinery and is expected to be operational in 1993. It is expected to use conventional heavy crude oil, bitumen and some semi-processed heavy crude oil as feedstock.

Whether upgrading is profitable depends critically on the price differentials between heavy crudes, including bitumen, and light crude oil. In the following subsections we will outline the expected relationship between light/heavy crude oil price differentials and synthetic crude oil supply from upgraders.

7.3.6.1 Price Differentials

Prices for bitumen and heavy crude oil are lower then the reference light crude oil prices. This difference in price, frequently referred to as the "price differential", depends mainly on the quality of heavy crude oil or bitumen relative to reference light crude. For example, the higher the viscosity, the larger is the price differential and the lower the price.

Additional refining costs must generally be incurred in order to "upgrade" conventional heavy crude oil and bitumen to higher value synthetic crude oil. Upgrading is economically attractive when differentials exceed the costs of upgrading. The economic viability of upgrading projects is thus largely dependent on the magnitude of the price differential between heavy and light crude oil. Depending on the type and the location of a facility, the additional processing cost associated with upgrading that has to be recovered can vary from about \$C 45/m^3 to \$C 75/m^3 (\$US (1990) 6-10 per bbl). Adding upgrading capacity to existing U.S refineries would be at the low end of the range and construction of stand alone upgraders in Alberta would be at the high end of the range. Costs for upgrading at existing refineries in Edmonton would fall approximately in the middle of this range.

In recent years, average price differentials have been about \$C 38/m^3 (\$US 5/bbl). Although recent changes in crude oil supply patterns related to the 1990-91 Gulf conflict have had the effect of increasing differentials, we do not consider this to be representative of the longer-term outlook. We anticipate in the control case that there will be moderate growth in price differentials for domestic light

and heavy crude oils over the projection period, from a pre-invasion level of approximately $US 5/bbl to $US 7.50/bbl (1990 dollars) in 2010. This projection is based on the results of our consultations and on the following considerations:

- gradual increases in the proportion of heavy crudes in world crude oil supply are probable as development of heavy crude oil and bitumen supply sources becomes more attractive under the control case crude oil price assumptions;
- as crude oil prices increase, the domestic supply of heavy crude oil is expected to increase, particularly as a result of increases in bitumen production;
- indigenous supplies of light crude oil in the United States and Canada are declining, while at the same time demand for light products remains relatively high; and
- as the requirement for upgrading increases as a result of the factors listed above, the costs associated with the addition of upgrading facilities at refineries are expected to increase as these refineries are progressively less well-suited to accommodate such expansions (at the same time, capacity constraints on the transportation system could limit access by refiners in the U.S. northern tier market to alternative supply from offshore sources).

However, we recognize that the price differential is dependent on the complex interaction of numerous factors. For example, increases in supply from large world reserves of light crude oil and expansion of the U.S. pipeline capacity to deliver this crude oil to the Chicago market could offset some of the factors leading to higher price differentials. A projection of future price differentials thus is fraught with uncertainty. The implications of alternative views regarding light/heavy crude price differentials on upgrading and on heavy crude exports are discussed in the following section and in section 7.4.2.2, respectively.

Low crude oil prices as projected in the low oil price sensitivity case discourage development of heavy crude oil and bitumen, resulting in lower supply and less need for expansion of upgrading facilities. In such a scenario we project differentials to remain relatively flat at $US 5/bbl. Conversely, in the high crude oil price sensitivity case we would expect that with increased supply availability differentials would increase more rapidly than in the control case, reaching $US 7.50/bbl by the year 2000, and then remain relatively constant for the remainder of the projection period. We have not projected an increase in the differential beyond $US 7.50/bbl, as this level appears to be high enough to facilitate upgrading in most situations.

At crude oil prices above $US 30 bbl an integrated bitumen production and upgrading facility is anticipated to be quite profitable. Producers we consulted indicated they would probably not hesitate to include an upgrading facility in their bitumen development plans if these price levels were to materialize.

7.3.6.2 Supply from Upgraders

In full operation, the Co-op and Bi-Provincial upgraders are expected to have a feedstock requirement of 16.3 thousand cubic metres per day, with a synthetic crude output of 14.4 thousand cubic metres per day (see Appendix Table A7-14).

Increasing differentials, and higher diluent prices triggered by high diluent demand associated with increased bitumen production, could lead to investment in upgraders at refineries in Edmonton, where the diluent included in the upgrader feedstock can be recovered and recycled for further use as diluent. However, large capital requirements and marginal economics make construction of Canadian upgrading facilities beyond those at the Co-op and Bi-Provincial upgraders very uncertain.

In the control case, we have assumed that one upgrader at an Edmonton refinery will proceed and commence operations in 2004. The feedstock for this upgrader is assumed to be 8.3 thousand cubic metres per day of blended bitumen. With this additional upgrader, the blended heavy crude oil feedstock required for upgrading would reach 25 thousand cubic metres per day by the end of the projection period. The bitumen is converted to about 20.5 thousand cubic metres per day of synthetic crude, and 4.5 thousand cubic metres per day of diluent can be recycled. Assuming this project proceeds and the export potential described in section 7.4.2.2 materializes, we anticipate that there will be a sufficient market to absorb the bitumen supply projected in the control case.

In the high oil price sensitivity case we project two upgraders in Edmonton, whereas in the low oil price sensitivity case we anticipate no upgrading in Edmonton.

Whether upgrading in Edmonton will proceed is uncertain, as it will

depend on future differentials, the cost of upgrading (which will be influenced by technological change over the projection period) and other factors. Lower differentials than assumed in our projection imply higher bitumen prices and this would tend to make bitumen development under our control case oil prices even more profitable, further increase bitumen supply. To the extent that differentials are insufficient to warrant investment in upgrading at Edmonton, the additional supplies would have to be absorbed in the export market. A discussion of export markets is provided in Section 7.4.

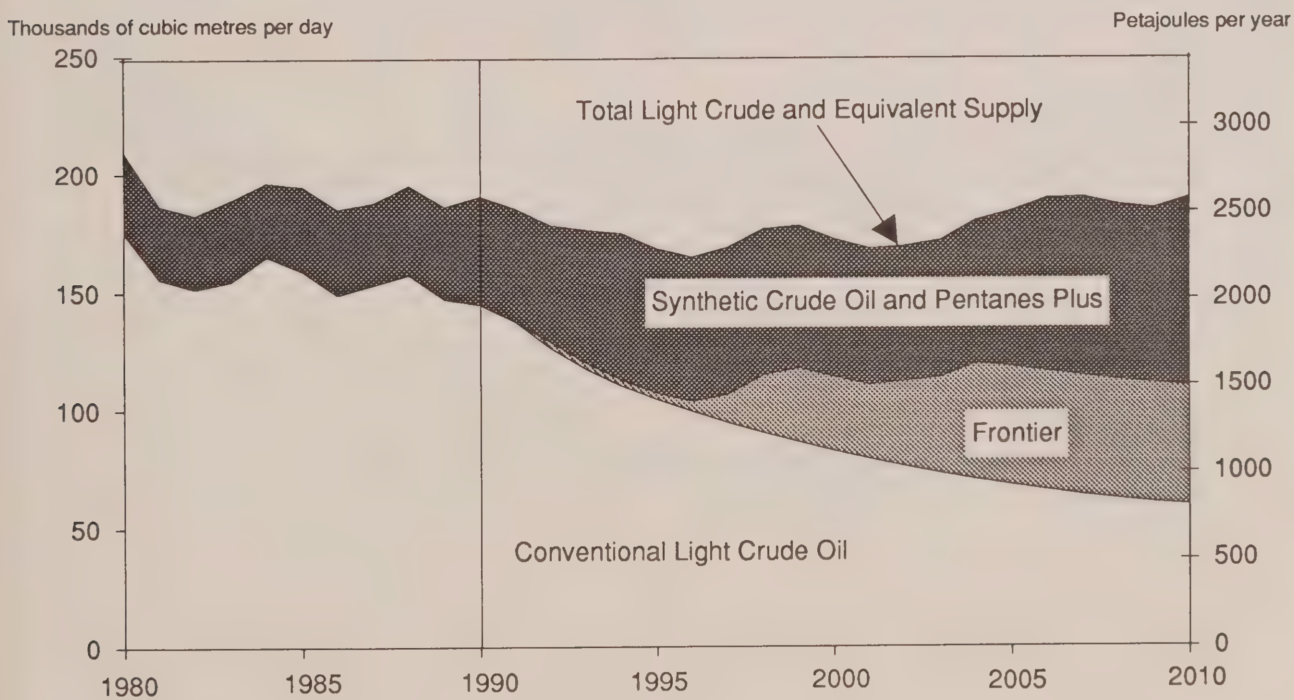
7.3.7 Total Supply

In this section the various components of the supply projection are consolidated, first into projections of total light crude oil and equivalent supply and the total and net available blended heavy crude oil supply and, finally, into a total projection of crude oil and equivalent supply.

7.3.7.1 Light Crude Oil Supply

The supply of light crude oil and equivalent includes conventional light crude oil from the WCSB, conventional frontier supplies, synthetic crude oil from integrated mining plants and from upgraded in situ bitumen production, and any pentanes plus that is not required as a diluent for bitumen. In the control case the total supply of light crude oil is about the same at the end of the projection period as it was in 1989 and 1990 (Figure 7-14). Although the supply of conventional light crude from Western Canada declines steadily, the projected commencement of East Coast Offshore and other frontier production, together with anticipated increases in synthetic crude oil supply from the upgrading of heavy crude oil and bitumen, largely offsets this decline. However, the increased synthetic crude oil supply alone is not sufficient to offset the decline in conventional light crude oil supply from Western Canada. Projections of individual supply components are summarized in Appendix Table A7-14. Supply of light crude and equivalent declines by about 13 percent from 1990 to 1996. In 1996 production from Hibernia commences which, together with production from the Mackenzie/Beaufort commencing in 2004 and increased synthetic crude oil production from mining and upgrading, more than offsets the effect of continued declining production of conventional light crude in Western Canada over the remainder of the projection period.

Figure 7-14
Light Crude Oil and Equivalent Supply



This projection implies a significant change in the sources of domestic light crude supply. While conventional light crude from the WCSB contributed about 78 percent of the total light crude supply in 1989, it contributes only about 31 percent by 2010. At that time, synthetic crude oil and frontier supply comprise 42 and 27 percent respectively of total light crude oil supply.

There is considerable uncertainty associated with this light crude and equivalent projection, particularly with regard to the timing and development of new projects such as frontier and synthetic supply sources. The timing of these projects is highly sensitive to crude oil prices and the applicable fiscal regime.

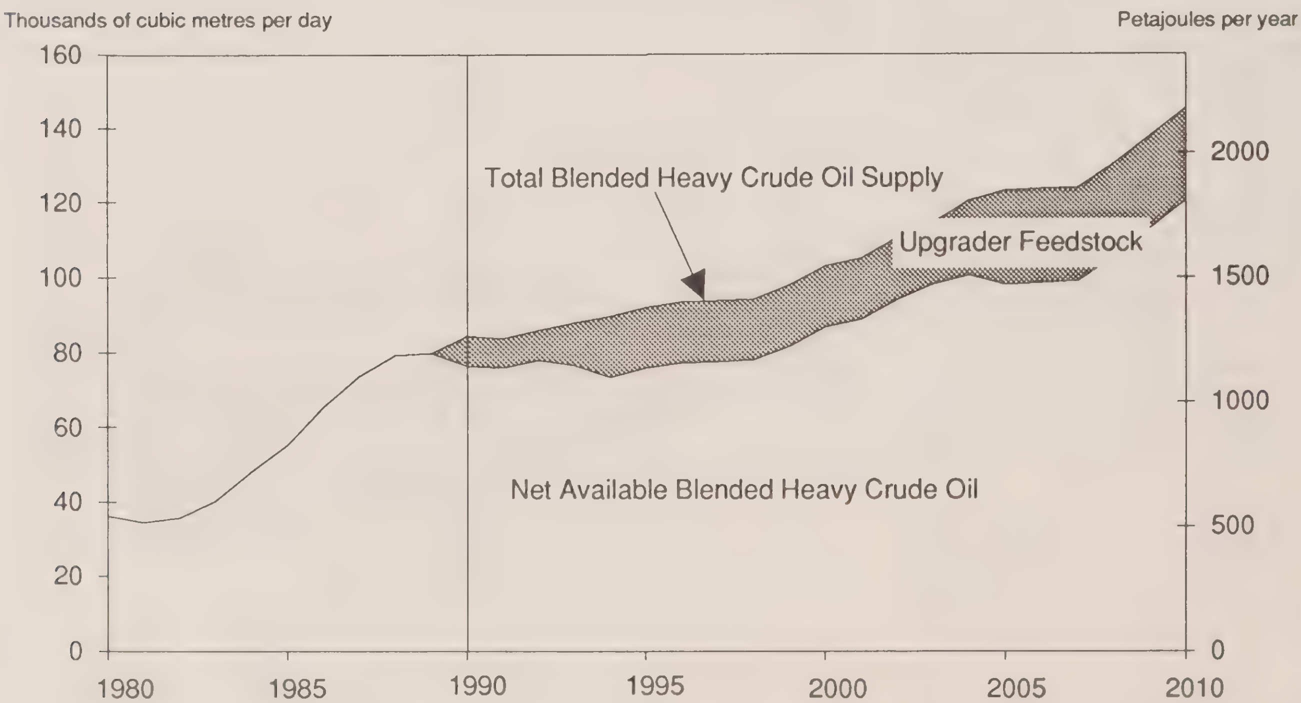
7.3.7.2 Heavy Crude Oil Supply

The projection of total blended heavy crude oil supply is comprised of conventional heavy crude from established reserves and reserves additions, bitumen from in situ production and diluent required for blending. The blended heavy crude to be used as feedstock for upgrading is deducted from the total blended heavy crude supply to arrive at a net volume of blended heavy crude available as refinery feedstock. Figure 7-15 depicts the total blended heavy crude oil supply, including diluent, as well as the breakdown into the supply available for refinery feedstock and the volume that is expected to be used as feedstock to the upgraders. Total blended heavy crude oil supply increases by about 86 percent during the projection period, whereas the net available blended heavy crude supply increases by about 54 percent.

Projections for the individual heavy crude supply components are provided in Appendix Table A7-14.

Conventional heavy crude oil production remains relatively constant during the early years of the projection period, and gradually declines thereafter. The supply of conventional heavy crude oil is in 2010 about 76 percent of the 1990 level. The decline in supply of conventional heavy crude oil is more than offset by increases in bitumen supply, which increases by about 250 percent to approximately 73 thousand cubic metres per day in 2010. This is accompanied by a commensurate increase

Figure 7-15
Heavy Crude Oil Supply



in diluent requirements. While conventional heavy crude production contributed about 59 percent of the total blended heavy crude oil supply in 1990, it is expected to contribute only 26 percent in 2010.

Some heavy crude oil serves as upgrader feedstock and is thus converted into a light synthetic crude, with some diluent possibly being recycled. The feedstock requirements for upgraders increase during the projection period as new upgrading capacity becomes available, reaching a total of about 25 thousand cubic metres per day in 2010. The available supply of blended heavy crude oil, net of upgrader feedstock requirements, increases by about 58 percent between 1990 and 2010, to about 121 thousand cubic metres per day. This is the available blended heavy crude for refinery feedstock.

There is considerable uncertainty associated with heavy crude oil supply, particularly with respect to bitumen development which is both price and market sensitive. As indicated in the previous section, the upgrader feedstock requirements also are uncertain due to the price sensitivity associated with upgrader development.

7.3.7.3 Total Crude Oil and Equivalent Supply

In total, the supply of crude oil and equivalent is expected to increase by about 16 percent during the projection period. The increasing contribution of synthetic crude oil, frontier supply, pentanes plus and bitumen production during the projection period more than offsets declining conventional light and heavy crude oil production from the WCSB (Figure 7-16).

While the total volume of crude oil and equivalent available changes modestly, the quality of the crude oil and the regional distribution of supply changes considerably. This change in composition is depicted in Figure 7-17. In 1990, all supply came from Western Canada, and of this, 71 percent was light crude and equivalent and 29 percent was blended heavy crude. By the end of the projection period, about 45 percent of the total crude oil supply is projected to be light crude and equivalent from Western Canada, 4 percent comes from the Mackenzie/Beaufort area and 12 percent from the East Coast offshore. The share of heavy crude

Figure 7-16
Total Supply of Crude Oil and Equivalent

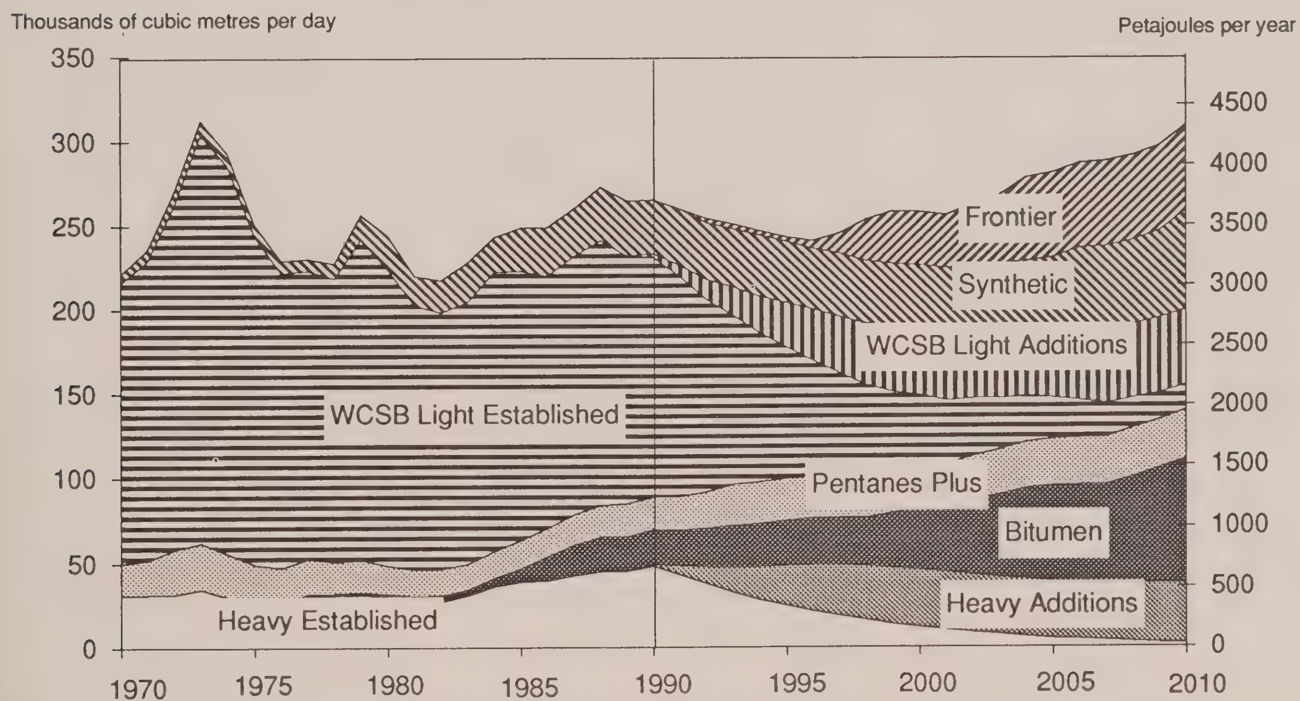
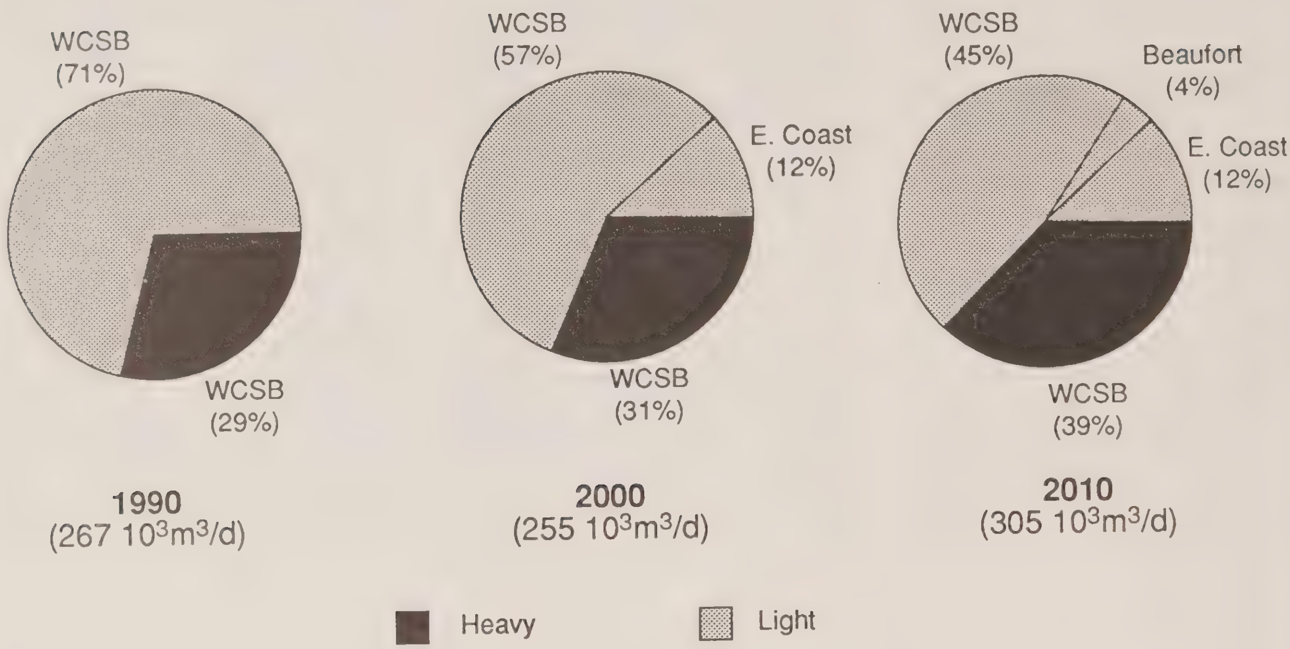


Figure 7-17
Composition and Source Locations of Total Crude Oil and Equivalent Supply



oil is expected to increase to 39 percent by 2010.

The extent to which these supply projections are realized will depend on many factors, but most importantly on the actual crude oil prices which materialize during this period.

The significant changes to the composition and source of our control case crude oil supply over the projection period impact on the Canadian refinery configuration and on the crude oil transportation system. The implications of this are discussed later in this chapter.

7.3.7.4 Price Sensitivity of Crude Oil Supply

Price is only one of many uncertainties that could influence our crude oil supply projections. However, for our sensitivity cases we have focussed on crude prices because the price outlook can change rapidly and because it has a significant impact on crude oil supply over the range of prices considered in our analysis. The upper and lower bounds of our crude oil price range have been discussed in Chapter 2.

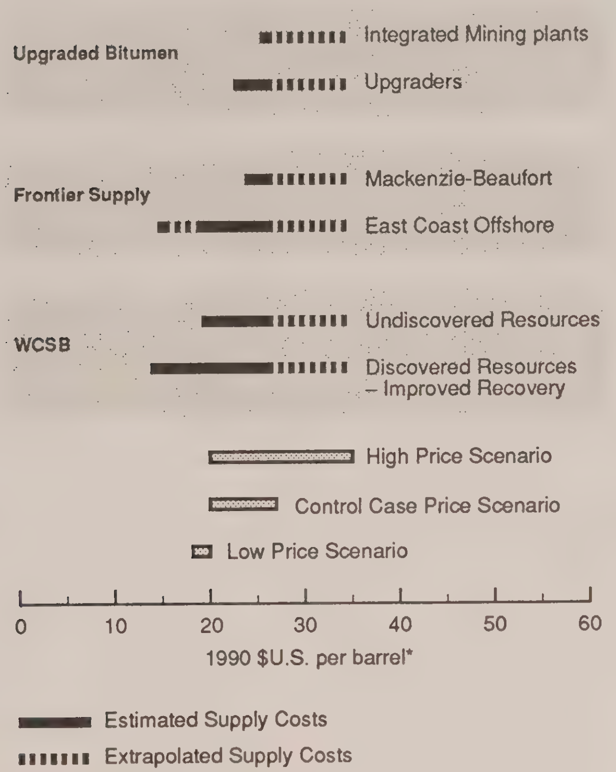
Figure 7-18 compares the range of supply costs used in our analysis to the three crude oil price scenarios and is indicative of the impact of alternative price outlooks on the economic viability of specific supply sources.

The outlook for **light crude oil and equivalent supply** is not very price sensitive in the short term as major projects that could be accelerated or delayed by changes in the price outlook have long lead times and because higher reserves additions of conventional crude oil in Western Canada in our high oil price sensitivity case are in large part offset by higher diluent requirements for blending with conventional heavy crude and bitumen. In the longer term, changes in the timing of several major projects have a significant impact on supply relative to the control case (Figure 7-19).

In the low oil price sensitivity case, no new integrated oil sands plants or upgraders are constructed and further frontier development is restricted to the projects that are underway (Hibernia and Cohasset/Panuke) and the Terra Nova project, which is viable under the low case price projection and

Figure 7-18

Comparison of Range of Supply Costs and Crude Oil Price Scenarios



*Source: Table 7-3

commences production in 1998 as in the control case.

Higher crude oil prices in the high oil price sensitivity case are expected to accelerate development of the oil sands. Consequently we have included three integrated mining plants in this case, as compared to two in the control case. Although the higher price levels in this sensitivity case would support more aggressive mining development, we believe it likely that these projects will be constructed about four years apart given the size of these projects and the specialized manpower requirements for constructing and operating these plants. Increased bitumen supply is expected to increase price differentials and we therefore included two upgraders in Edmonton, instead of one. Finally, we accelerated supply from the frontier regions, with the timing of projects determined in the same manner as for the control case. Terra Nova begins production in 1997. Further development off the East Coast leads to a stable production level of about 46 thousand cubic metres per day in 2004, as compared to about 38 thousand cubic metres per day in the control case. In addition, production from the Amauligak field in the Beaufort Sea commences in the year 2000, rather than in 2004, with total supply from this region amounting to about 19 thousand cubic metres per day rather than the 12 thousand cubic metres per day anticipated in the control case. However, this high price case may not reflect the full development potential of bitumen and frontier resources and a somewhat higher supply level could be achieved if these prices were to materialize.

The outlook for net available blended heavy crude oil supply is dominated by the impact of alternative price scenarios on the projection of bitumen supply and by changes in upgrader feedstock requirements. The cases also reflects changes in diluent requirements for bitumen.

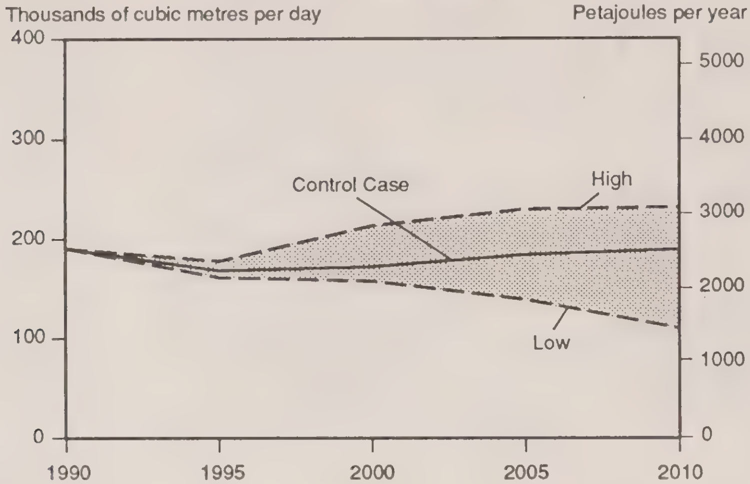
In the low oil price sensitivity case, development of new bitumen projects is not profitable until late in the projection period. Projects that are currently operating are generally expected to continue operating, keeping bitumen supply fairly stable until approximately 2006 when prices reach a level sufficient to warrant new project development. The overall decline in net available blended heavy crude oil supply up to the year 2006 (Figure 7-19) is thus essentially attributable to a decline in conventional heavy crude oil, as lower crude oil prices result in lower reserves additions than in the control case. (Upgrader feedstock requirements remain unchanged after 1994 when the Bi-Provincial upgrader is assumed to be fully operational).

In the high oil price sensitivity case, conventional heavy crude supply is expected to increase gradually to about 60 thousand cubic metres per day by the year 1998, due to higher reserves additions than in the control case, and then to decrease to current levels by the end of the projection period. Bitumen supply increases signifi-

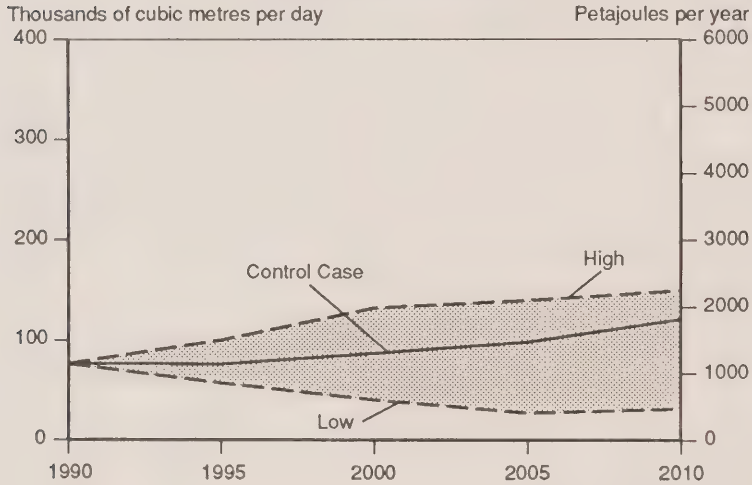
Figure 7-19

Productive Capacity of Crude Oil and Equivalent - Total Canada
Price Sensitivities around Control Case

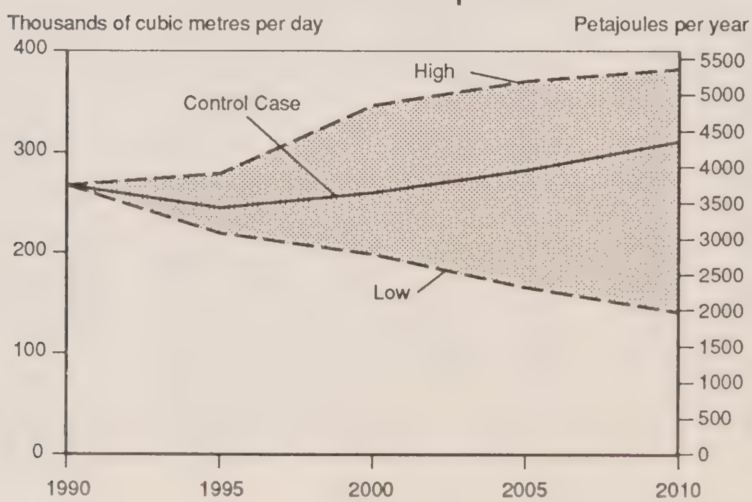
Light Crude Oil and Equivalent



Total Heavy Crude Oil



Total Crude Oil and Equivalent



cantly throughout the projection period, reaching a level of about 90 thousand cubic metres per day in the year 2010, whereas upgrader feedstock requirements reach a level of 31 thousand cubic metres per day during the last five years of the projection period. Bitumen supply is about 20 thousand cubic metres per day higher than the level projected for the control case. An even more aggressive development of bitumen is certainly possible given the size of the resource base. However, this could have implications for price differentials and upgrading, unless existing and new markets can absorb further increases in supply.

The total supply of crude oil and equivalent is the sum of the light and heavy crude oil supply projections discussed above. In the low oil price sensitivity case there is a gradual decline in domestic supply, whereas supply increases rather dramatically in the high oil price sensitivity case, especially between 1995 and 2005.

7.4 Refinery Balances and Crude Oil Supply/Demand Profiles

In the preceding sections of this chapter, we have described the basis for our projections of light and heavy crude oil supply. As illustrated in Figure 7-1, Canadian refinery feedstock requirements are met from domestic crude oil supply and crude oil imports. Canadian crude oil production is also exported. Additionally, the projected domestic demand for petroleum products must be satisfied through refinery runs, with allowance for the import and export of products.

In this section, we first review domestic petroleum product demands and describe the basis for our projection of refinery capacities, product imports and exports and feedstock requirements. This is followed by an examination of supply and demand balances for light and heavy crude oil, and the related matters of imports and exports of crude oil. We then summarize Canada's trade in crude oil and petroleum products and discuss the major implications of the crude oil supply and demand outlook as they pertain to Canadian refineries and pipeline systems.

The projections described in this section have been developed in the context of the declining domestic conventional light crude oil supply, increasing domestic heavy crude oil availability and moderate growth in domestic demand for petroleum products described earlier in the report.

Figure 7-20 provides an overview of the major domestic crude oil pipeline systems and refining centres in Canada. Domestic crude oil production is obtained primarily from the provinces of British Columbia, Alberta and Saskatchewan and from the Norman Wells field in the North West Territories. Crude oil shipments to the west coast are through the Trans Mountain Pipe Line Company Ltd. (TMPL) system. Crude oil shipments to Eastern Canada as far as Montreal and to export markets in the Northern Tier of the United States occur via the Interprovincial PipeLine Company (IPL) system. Refining centres in Ontario have obtained crude oil supply from Western Canada, whereas those east of Montreal are supplied entirely from offshore sources through water-borne imports. Montreal refineries have historically obtained most of their crude oil feedstock from Western Canada and from offshore imports via the Portland Pipeline system. In 1990, total crude oil and product imports were about 100 thousand cubic metres per day and exports were approximately 135 thousand cubic metres per day.

7.4.1 Refinery Balances

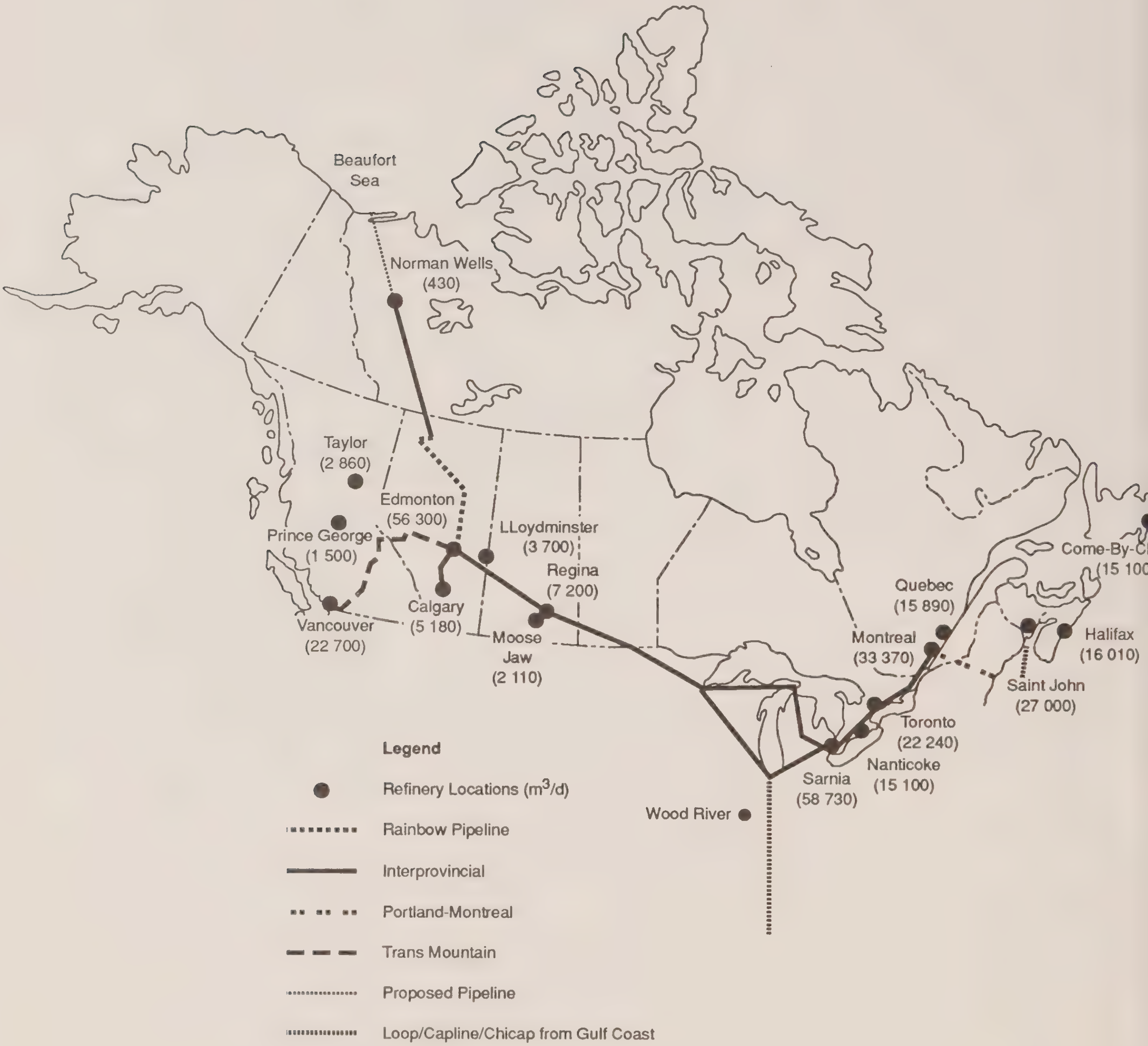
To assess the implications of trends in petroleum product consumption for crude oil supply and demand, product demands must be converted to the corresponding requirements for refinery feedstocks. Important factors accounted for in this regard are the total product demand, available refinery capacity, product imports and exports and the availability of refinery feedstock (i.e., light and heavy crude oil supply). Product demand was described in Chapter 4. In this section we outline our assumptions regarding refinery capacity and product imports and exports, and summarize the refinery feedstock requirements for our control case. The availability of feedstock is then discussed in further detail in Section 7.4.2.

7.4.1.1.Refinery Capacity

In the past decade Canadian refiners, in common with those throughout the world, have faced a series of rapidly changing circumstances, including highly volatile feedstock costs, reduced consumption of petroleum products and an altered product demand slate. As well, there have been significant changes to product specifications, with a shift to lead free gasoline and less demand for heavy fuel oil.

In adapting to these new realities, the global industry has changed in

Figure 7-20
Major Crude Oil Pipelines and Refining Areas



a number of ways. This adaptation is generally referred to as "refinery rationalization", and has included plant closures, refinery upgradings and, in some cases, construction of more efficient plants. Canada's refining sector has also undergone rationalization. As a result, the industry is now positioned to respond more efficiently to current and prospective feedstock availability, product markets, and environmental constraints.

In 1980, there were 37 refineries operating in Canada, with a combined distillation capacity of about 370 thousand cubic metres per day. By 1986, 11 refineries had closed and two others had been reduced in size. During the same period, two new plants came onstream and several others undertook small expansions. As well, in 1987 Petro-Canada's refinery in Newfoundland, which had been idle for several years, was sold to the Bermuda-based Newfoundland Energy Company. It commenced operations later in the year with a capacity of 16 thousand cubic metres per day. By the end of the 1980s, Canada's total refining capacity had stabilized at a level of about 305 thousand cubic metres per day (Table 7-5). Some ongoing rationalization can be expected; Petro-Canada closed its refinery at Taylor, B.C. in early 1991.

Since 1980, the refining industry has made improvements to its processing equipment to increase the production of light products such as gasoline, middle distillates (mainly diesel fuel) and jet fuels. Further improvements in product yields are expected, in order to meet changing product demands and specifications. In particular, the major challenges for refiners in the next few years will be to reduce sulphur levels in diesel fuel and to improve the quality of motor gasoline. These changes are the result of continually tighter product specifications, designed to bring about a reduction in emissions of lead, sulphur oxides and nitrogen oxides. Substantial capital investment will be required to meet these environmental standards.

Table 7-5

Canadian Refinery Capacities and Crude Runs 1990

(Thousands of Cubic Metres Per Day, Crude Oil and Equivalent)

	Capacity	Crude Runs	Utilization Rate %
Atlantic Provinces	58.1	47.5	82
Quebec	49.3	43.9	89
Ontario	96.1	82.8	86
Prairie Provinces	75.0	63.3	84
British Columbia/N.W.T	27.1	23.8	88
Total Canada	**305.6**	**261.3**	**86.0**

The refining industry in Canada is generally highly competitive as well as capital intensive, with the consequence that margins are relatively poor and profitability low. We anticipate, therefore, that the industry will likely strive to minimize its capital investment over the projection period, limiting projects to those related to environmental standards and changes necessary to meet the specific demands for petroleum products in the marketplace.

In 1990, Canadian refineries, primarily in the Prairie Region and Ontario, consumed the bulk of the synthetic crude production from the Syncrude and Suncor mining plants, with the remainder being exported to the United States. Depending on the quality of the incremental supplies of synthetic crude oil from mining plants or upgraders which are projected to come onstream during the projection period, some investment may be required so that Canadian refineries can process these new supplies. Otherwise, these feedstocks would have to be exported.

7.4.1.2 Product Exports and Imports and Refinery Feedstock Requirements

Projections of refinery feedstock requirements (Table 7-6) were developed starting from the estimates of demand for petroleum products. We took into account product yields from available crude oils, likely needs for inter-regional transfers, and anticipated levels of imports and exports of petroleum products. Importantly, it was assumed for the longer-term that necessary refinery investments would be made to ensure refinery yields correspond as closely as

Table 7-6

Refinery Feedstock Requirements and Sources

(Thousands of Cubic Metres per Day)

	Control Case					
	1990	1993	1995	2000	2005	2010
Demand for Petroleum Products	239	239	242	251	267	288
Product Exports	32	34	34	34	34	34
Product Imports	(20)	(27)	(27)	(30)	(37)	(46)
Inventory Change and Refinery Use	10	16	16	16	16	18
Refinery Feedstock Requirements	261	262	265	271	280	294
Supplied by:						
Partially Processed Oil, Other Material and Gas Plant Butanes	(12)	(13)	(13)	(13)	(13)	(13)
Crude Oil	249	249	252	259	267	281
Light	225	226	227	232	238	249
Heavy	25	24	25	27	29	32

Note: The numbers in this table have been rounded.

Sources: Appendix Table A7-15 and Tables 7-7 and 7-8.

possible with light product demand and that the characteristics of the various products produced will meet the more stringent quality specifications imposed for environmental purposes.

Total domestic demand for petroleum products increases from 239 thousand cubic metres per day in 1990 to 288 thousand cubic metres per day by the year 2010, an increase of 49 thousand cubic metres per day. Of this increase about 20 thousand cubic metres per day is attributable to growth in heavy fuel oil demand.

In our analysis, natural gas prices are projected to increase more rapidly than the price of fuel oil and, during the latter half of the outlook period, the price of natural gas in the industrial market in Ontario and Quebec exceeds the price of heavy fuel oil (HFO) by more than 10 percent. Consequently, the demand for heavy fuel oil increases - particularly over the last 5 years of the outlook - as some industrial demand in Quebec and Ontario switches from natural gas to HFO. As noted in Chapter 4, there are a number of uncertainties related to the projections of relative end use prices and several reasons why the switching from natural gas to heavy fuel oil may not occur to the extent projected in the last few years of the outlook.

In addition to the domestic demand for petroleum products, we anticipate that exports and imports of petroleum products will continue to play an important role in balancing supply and demand. Our assessment is that refiners and independent marketers will export and import products during the projection period to overcome seasonal and regional imbalances in demand and to operate refineries as efficiently as possible. As well, Canadian exporters with established markets in the United States are expected to retain these customers and to develop new outlets, at least in the very short term. For example, the Come by Chance refinery in Newfoundland, which was recommissioned as an export refinery, is expected to be able to continue to export a substantial portion of its production.

Total exports of petroleum products in 1990 were about 32 thousand cubic metres per day. We estimate that exports will increase to about 34 thousand cubic metres per day in 1991 and remain at roughly that level during the review period as exports are maintained to established markets in the U.S. Over 50 percent of these exports will be from the Atlantic region.

In view of the projected growth in domestic demand and the assumption that there will be a modest increase in product exports, the

following options exist in terms of satisfying these demands: increase refinery utilization rates, expand domestic refinery capacity and/or import additional petroleum products.

In 1990, total imports of petroleum products averaged 20 thousand cubic metres per day, which was less than historical levels. Some large industrial consumers and utilities will continue importing heavy fuel oil for their own consumption. As well, we expect independent marketers to import oil products on a spot basis, taking advantage of periods of low international spot prices. We expect product imports to rise to about 27 thousand cubic metres per day in 1991, to 30 thousand cubic metres in 2000 and to 46 thousand cubic metres per day in 2010. As a consequence of the increasing domestic demand for heavy fuel oil late in the projection period discussed above, the estimate of product imports in 2010 includes about 20 thousand cubic metres per day of heavy fuel oil to satisfy demands in Quebec and Ontario. It is uncertain whether there is scope to substantially increase the level of HFO imports, as it would require changes to the transportation system and other petroleum industry infrastructure and it assumes that the refinery capacity is available elsewhere in the world to provide these volumes to meet Canadian requirements. However, the substantial increase in imports does not occur until late in the projection period and we consider the projected level of product imports to be manageable at least over the period to 2000. Beyond that time it may be difficult to accommodate HFO imports of the size envisaged by our outlook.

There are a number of reasons why increased product demand is likely to be met primarily by domestic refiners rather than increased imports over the majority of the projection period, the most important of which is that most of this growth in demand can be met by increasing the utilization of existing refinery capacity. In this connection, capacity utilization in the Atlantic provinces is projected to rise from 82 percent in 1990 to 85 percent by the end of the projection period. Capacity utilization increases in Quebec from 89 percent to nearly 95 percent and in Western Canada from 85 percent to 97 percent by 2010. In Ontario, barring new capacity being built, refineries would be operating at 94 percent of capacity by 2000 and at slightly in excess of 100 percent by 2010. However, given the long lead times involved and the relatively small capacity increases required, the additional capacity can probably be accommodated by debottlenecking at a rather modest incremental cost in conjunction with the projected substantial investments necessary to meet environmental standards.

In Eastern Canada (i.e., Ontario and east), crude runs are projected to increase by 12 percent, from 174 thousand cubic metres per day in 1990 to 195 thousand cubic metres per day by 2010. In Western Canada, crude runs are anticipated to rise at about the same rate, from 87 thousand cubic metres per day in 1990 to nearly 99 thousand cubic metres per day by 2010.

In recent years, some refiners have been making inter-regional transfers of semi-processed oil. During the projection period, we expect that these transfers, together with transfers of finished products, will continue, especially between Edmonton and locations in British Columbia.

In summary, we anticipate that over the majority of the projection period the growth in domestic demand for petroleum products can be met by increased utilization of existing domestic refinery capacity and some modest debottlenecking in conjunction with projected investments necessary to meet environmental standards. The growth in demand for heavy fuel oil, which occurs late in the projection period, would have to be satisfied by a substantial growth in product imports to Ontario and Quebec, the feasibility of which is uncertain.

The underlying premise in the above discussion is that Canadian refiners will have continued access to light crude supply and there will be limited investment at refineries in Eastern Canada to add capacity to process other grades of feedstock. These issues are examined in the following section.

7.4.2 Crude Oil Supply/Demand Profiles

In the previous sections, we outlined our assumptions regarding refinery capacity and product exports and imports necessary to satisfy domestic product demand. This section examines in more detail the relationship between refinery feedstock requirements and domestic crude oil supply, and crude oil exports and imports. It also describes the implications of our analysis for major crude oil pipeline systems.

Refineries in Canada generally use light crude oil to manufacture petroleum products, while the bulk of Canadian heavy crude oil production is exported. Thus, in order to assess the extent to which domestic feedstock demand can

be satisfied from indigenous production, it is necessary to determine supply and demand balances for light and heavy crude oils separately. It should also be mentioned that, within the range of light crude oils, quality differences exist particularly with regard to sulphur content. Light crude oils with low levels of sulphur are referred to as sweet crudes while those with a relatively high sulphur content are known as sour crudes.

7.4.2.1 Light Crude Oil

In Table 7-7, we show the supply and demand outlook for light crude oil and equivalent.

In 1990, production was 195 thousand cubic metres per day, compared with domestic refinery demand of 225 thousand cubic metres per day. Canada exported about 45 thousand cubic metres per day of light crude oil in 1990, mainly to the U.S. midwest region. Figure 7-21 shows the disposition of these light crude oil exports. Imports of light crude oil to eastern Canada in 1990 were 75 thousand cubic metres per day, resulting in net imports of 30 thousand cubic metres per day.

During the projection period, we have assumed that Western Canadian and Mackenzie/Beaufort crude oil will be used first to satisfy refinery demand in Western Canada and exports to U.S. markets, albeit at somewhat reduced levels. Current patterns for the disposition of Canadian crude oil can be expected to continue. In particular, it is anticipated that market forces could result in sustained levels of light crude oil exports of between 20 thousand and 30 thousand cubic metres per day. A level of 20 thousand cubic metres per day has been used for developing the supply and demand outlook.

Our analysis was based on a refinery-by-refinery assessment of the likely crude oil acquisition intentions of U.S. buyers. It reflects our expectation that some crude oil currently shipped to U.S. refiners on the Rangeland system would likely continue to be exported and that certain other U.S. refiners, which are at least partially dependent on Canadian supply, would continue to purchase Canadian crude oil. Finally, the capability of Canadian refiners, particularly in Ontario, to process light sour, synthetic and heavy crude oil was taken into consideration, in that the quantities currently being used represent close to maximum capability based on existing refinery configurations. For the reasons discussed earlier, we anticipate that Canadian refiners will be reluctant to make significant investments to handle incremental volumes of these crudes, provided that alternative sources of supply are available.

The balance of Western Canadian light crude supply would then be available for Ontario and Quebec. The anticipated decline in light crude oil production in Western Canada, together with the generally favourable economics of importing, have resulted in reduced throughputs on the

Table 7-7

Supply and Disposition of Light Crude Oil and Equivalent

(Thousands of Cubic Metres per Day)

Control Case

	1990	1993	1995	2000	2005	2010
Domestic Supply [a]	195	175	168	173	184	188
Imports	75	82	82	111	113	119
Total Supply	270	257	250	284	297	307
Total Domestic Requirements	225	226	227	232	238	249
Exports	45	31	23	52	59	58
Total Disposition	270	257	250	284	297	307
Net Imports	30	51	59	59	54	61

Notes: The numbers in this table have been rounded.
[a] Domestic supply is net of diluent requirements for pipelining heavy crude oil.

Sources: Appendix Table A7-16 and Table 7-9.

Figure 7-21

Exports and Imports of Light Crude Oil by Market
1990

(Thousands of Cubic Metres per Day)

Sarnia-Montreal pipeline in recent years. With the prospect of further declines in Western Canada supply, and more attractively priced offshore supplies, the Sarnia-Montreal pipeline is in the course of being shut down at the time of writing and it is therefore assumed that refining centres east of Ontario would be supplied entirely by offshore sources. Use of domestic light crude oil supply in Canada is anticipated to decline from 150 thousand cubic metres per day in 1990 to 130 thousand cubic metres per day in 2010.

We expect most of the offshore production from the east coast would be exported (probably to the United States), although final sales decisions have not yet been made. Of the companies involved in the development of the Hibernia field, including Gulf Canada, Chevron Canada, Petro-Canada and Mobil, only Petro-Canada has a refinery in Eastern Canada, at Montreal. Moreover, because of its high paraffin content refiners would likely have to make significant investments to be able to process this crude oil.

Light crude oil imports in 1990 of 75 thousand cubic metres per day represented about 33 percent of total light crude oil requirements. Imports are projected to increase to 119 thousand cubic metres per day by 2010, representing 48 percent of total light crude runs. Most of this growth in imports is projected to occur in Ontario. To the extent that Ontario refiners find Western Canadian supply to be uncompetitive, there could be an even greater dependence by Ontario on imported crude oil supply. Later in this chapter we discuss the transportation systems which could be used to import the required supplies.

7.4.2.2 Heavy Crude Oil

The blended heavy crude oil supply available for refinery feedstock increases from 77 thousand cubic metres per day in 1990 to 121 thousand cubic metres per day by 2010, or by more than 50 percent, primarily as a result of an increase in bitumen production. As has been the case for many years, productive capacity exceeds domestic requirements throughout the projection period (Table 7-8).

The refineries in Canada which rely on domestic crude oil were, for the most part, designed to process light sweet crude oil. Only limited volumes of domestic heavy crude oil are used during the summer for the manufacture of asphalt. In the short term, it is unlikely that Canadian refineries will significantly increase their use of heavy crude oil given the large capital requirements associated with the construction of the necessary processing facilities and the uncertainty about the anticipated return on this investment, which will depend on future price differentials between heavy and light crude oil. As discussed in section 7.3.6.1, these price differentials are expected to increase slowly. Furthermore, U.S. refineries can expand existing upgrading facilities at a marginal cost below the cost that would be incurred by Canadian refiners that do not have existing upgrading facilities. In the longer term, if crude oil prices increase, crude oil price differentials may widen. We anticipate that investment in refinery upgrading in Edmonton will occur later in the projection period as price differentials between light and heavy crude oil widen and diluent availability becomes a greater concern. However, investment in such upgrading projects is expected to remain highly uncertain and alternative markets for heavy crude may have to be found if these projects do not materialize.

Table 7-8

Supply and Disposition of Heavy Crude Oil

(Thousands of Cubic Metres per Day)

Control Case

	1990	**1993**	**1995**	**2000**	**2005**	**2010**
Domestic Supply [a]	77	77	76	87	98	121
Imports	7	7	7	7	7	7
Total Supply	84	84	83	94	105	128
Total Domestic Requirements	25	24	25	27	29	32
Exports	59	60	58	67	76	96
Total Disposition	84	84	83	94	105	128
Net Exports	52	53	51	60	69	89

Notes: The numbers in this table have been rounded.
[a] Domestic supply includes diluent.

Sources: Appendix Table A7-16 and Table 7-9.

The estimated domestic requirement for heavy crude oil, excluding upgrader feedstock, is projected to increase from 25 thousand cubic metres per day in 1990 to 32 thousand cubic metres per day in 2010. Seven thousand cubic metres per day is currently imported by refineries in Quebec and the Atlantic Provinces; this level of imports is expected to continue during the projection period for use in the production of such products as asphalt. Demand for heavy crude oil as a proportion of total crude oil requirements is constant at roughly ten percent throughout the projection period.

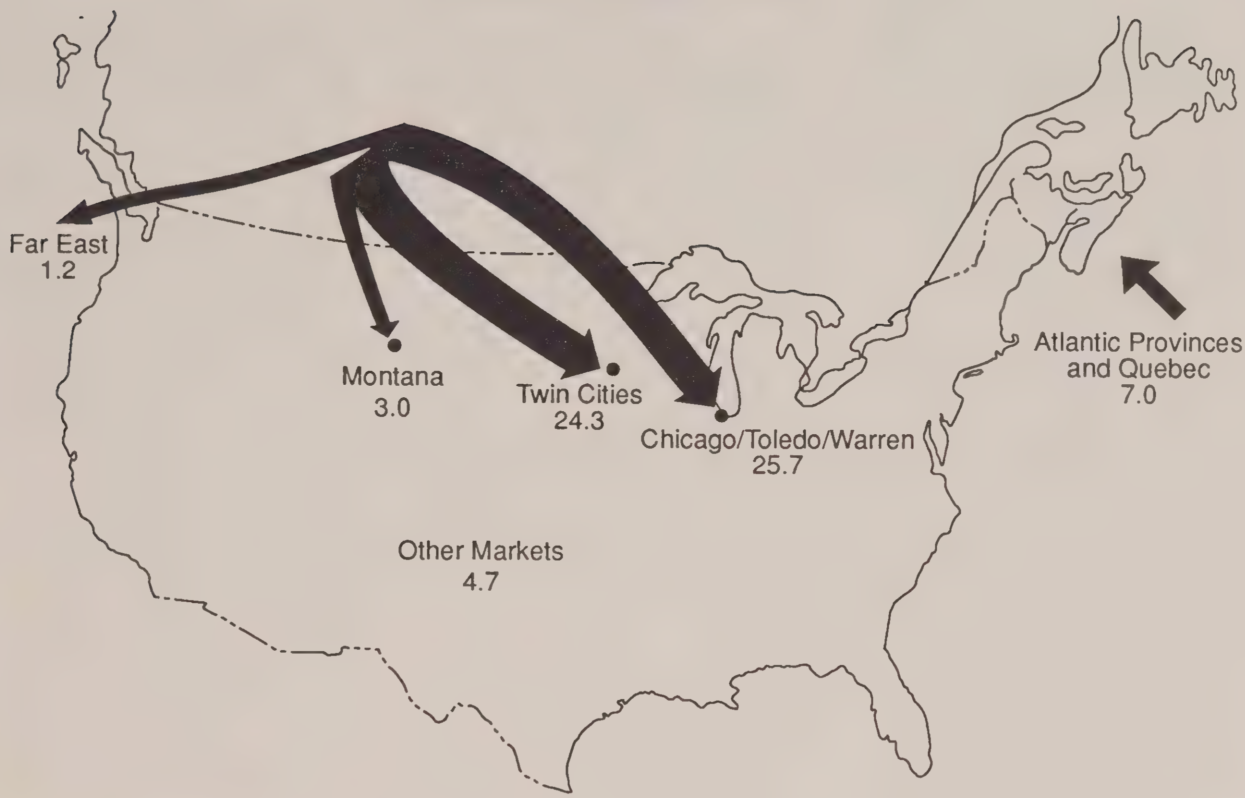
Canada currently exports the bulk of its heavy crude oil production, primarily to the United States. Figure 7-22 identifies the main locations to which Canadian heavy crude oil was exported in 1990. The major U.S. market is the Northern Tier (the midwest states and Montana), where total refining capacity is roughly 275 thousand cubic metres per day. Of this, approximately 90 thousand cubic metres per day represents heavy crude oil processing capability. Our exports of heavy crude oil to this market currently amount to 56 thousand cubic metres per day.

With regard to the outlook for the export market potential for Canadian heavy crude oil, we have developed our projection using an approach which reflects various strategic and institutional trends in the United States, together with a

Figure 7-22

Exports and Imports of Heavy Crude Oil by Market
1990

(Thousands of Cubic Metres per Day)



refinery-by-refinery analysis of possible future investment decisions. Our approach took account of factors such as current and expected trade patterns for Canadian heavy crude oil, size-of-market assessments, scope for the development of new markets, the impact of future crude oil price levels on the ability of Canadian industry to compete internationally, and the current intentions of U.S. refiners to undertake upgrading investments. More specifically, our projection of the U.S. market for Canadian heavy crude oil is based on the following considerations:

- We do not expect major changes in U.S. product demand in the northern tier area served by Canadian heavy crude over the projection period;

- U.S. indigenous production currently supplying refineries in the Northern Tier is declining, particularly Wyoming sour crudes, providing an opportunity for Canadian heavy crudes to capture additional market share;

- the current availability of substantial refining capacity for heavy crudes in the Northern Tier has the potential for expansion at costs consistent with the lower end of the range of differentials that we are using. This is in contrast to the situation in Canada where refiners, for the most part, have not made these investments over the years, preferring instead to rely on ample supplies of domestic light sweet crude. Because U.S. refiners began an upgrading program some years ago, incremental investments are much less costly than in Canada;

- U.S. refiners have expertise and experience in handling these crudes and have indicated not only an intention to maintain Canadian supplies at current levels but to increase utilization of these crude oils, which would provide a potential for further market penetration by Canadian suppliers;

- the existence of an established transportation infrastructure for access to these markets by Canadian heavy crude producers; and

- the existence of established trading patterns and the interest of U.S. buyers in continuing to access a secure source of supply.

Another potential market for Canadian heavy crude oil in the United States is the Wood River, Illinois refining area, south of Chicago. This market is about 15 thousand cubic metres per day. We have assumed that Canadian heavy crudes will not penetrate this market over the projection period, as it is a highly competitive market subject to pressures from offshore imports. Moreover, the pipeline infrastructure would have to be put in place to allow Canadian crude oil to access this market.

Taken together, these factors suggest that Canadian heavy crude could well play an increasing role in meeting the Northern Tier demand for feedstocks over the projection period. To put Canadian heavy crude oil exports in perspective, it is perhaps worth mentioning that they essentially quadrupled during the 1980s, from 15 thousand cubic metres per day in 1980 to nearly 60 thousand cubic metres per day in 1990. In our control case, heavy crude oil exports are projected to increase by less than 15 percent during the decade of the 1990s. We project that growth will be somewhat higher from 2000 to 2010, at roughly 40 percent, but still well below the growth in the 1980s.

While we foresee opportunities for further penetration of Canadian heavy crude supply into Northern Tier U.S. markets, we recognize that there will continue to be strong competitive pressures in these markets. Additionally, to the extent that refinery upgrading projects in Western Canada do not materialize in the post-2000 period, there would have to be an even greater reliance on these markets to accommodate growth in bitumen production. In the absence of the installation of conversion capacity at Eastern Canadian refineries, the only alternative market outlet could be further penetration of Far East markets.

Trans Mountain Pipe Line's expansion in 1989 provided capacity to transport greater volumes of heavy crude oil to export markets other than the U.S. Northern Tier, while continuing to supply light crude oil and petroleum products to the domestic market. The system can now transport up to six thousand cubic metres per day of heavy crude oil to markets on the west coast from where it can be shipped to the United States, Pacific Rim countries, particularly Japan, and the rapidly growing economies of the Far East such as South Korea and Thailand. These markets have the potential for additional penetration by Canadian heavy crudes but are expected to remain highly competitive because of the availability of crude oils from the Middle East, Far East and, more recently, Australia. Given the increases in price in the control case, however, there would appear to be scope for Canadian exports to increase to Pacific Rim markets, if this were to become necessary.

7.4.2.3 Summary of Trade in Crude Oil and Products

In 1990, Canada was a net exporter of **crude oil and equivalent** to the extent of 22 thousand cubic metres per day. Net imports of light crude oil of 30 thousand cubic metres per day were more than offset by net exports of heavy crude oil of 52 thousand cubic metres per day. Our projections suggest that the net export position for total crude oil will decline to one thousand cubic metres per day in 2000, but thereafter increase to 28 thousand cubic metres per day by 2010 (Table 7-9).

Trade in **oil products** resulted in net exports of 12 thousand cubic metres per day in 1990. It is expected that this net export position will decline to about four thousand cubic metres per day in 2000. By 2010, there will be net imports of 12 thousand cubic metres per day reflecting the growing imports of heavy fuel oil discussed earlier.

The **overall** net export position, including crude oil and petroleum products, is projected to decline from 34 thousand cubic metres per day in 1990 to 16 thousand cubic metres per day by 2010.

7.4.2.4 Implications for Major Crude Oil Pipeline Systems

We conclude this chapter with a brief description of the major crude oil pipeline systems in Canada, and the impact that our projected crude oil supply and demand balances could have on their operation.

Trans Mountain (TMPL) and Interprovincial (IPL) operate the

Table 7-9

Exports and Imports of Crude Oil and Petroleum Products

(Thousands of Cubic Metres per Day)

	Control Case					
	1990	**1993**	**1995**	**2000**	**2005**	**2010**
Light Crude Oil						
Exports	45	31	23	52	59	58
Imports	75	82	82	111	113	119
Net Exports (Imports)	(30)	(51)	(59)	(59)	(54)	(61)
Heavy Crude Oil						
Exports	59	60	58	67	76	96
Imports	7	7	7	7	7	7
Net Exports (Imports)	52	53	51	60	69	89
Total Crude Oil						
Exports	104	91	81	119	135	154
Imports	82	89	89	118	120	126
Net Exports (Imports)	22	2	(8)	1	15	28
Products						
Exports	32	34	34	34	34	34
Imports	20	27	27	30	37	46
Net Exports (Imports)	12	7	7	4	(3)	(12)
Total Crude Oil and Products						
Exports	136	125	115	153	169	188
Imports	102	116	116	148	157	172
Net Exports (Imports)	34	9	(1)	5	12	16

Note: The numbers in this table have been rounded.

Sources: Tables 7-6, 7-7 and 7-8.

two major pipeline systems through which Canadian crude oil is moved to domestic and export markets. The Portland-Montreal pipeline also plays an important role in the delivery of offshore crude oil to Montreal refineries (Figure 7-20).

TMPL operates a pipeline for the shipment of crude oil, partially processed oil and refined petroleum products from receipt points in Alberta and British Columbia to delivery locations in B.C., principally the four refineries in the Vancouver area. The Westridge marine terminal in Burnaby, B.C. is used to accommodate shipments by tanker of light and heavy crude oils to offshore markets. TMPL also operates a lateral pipeline from Sumas, B.C. to Anacortes, Washington where four refineries are located. Although these refiners depend primarily on Alaskan North Slope crude oil, they take Canadian crude oil when it is priced competitively.

While crude oil constitutes a large portion of TMPL's throughput, significant volumes of refined petroleum products (gasoline and diesel) are delivered to product terminals at Kamloops, B.C. On

average, the pipeline shipped 26.5 thousand cubic metres per day of crude oil and products in 1990, of which 23 thousand cubic metres per day were shipped to domestic locations and 3.5 thousand cubic metres per day were transported to export destinations.

We expect domestic feedstocks shipped via TMPL to continue to meet British Columbia's requirements. As well, heavy crude oil tanker shipments from the Westridge dock, which have been made on a fairly regular basis since January 1987, are likely to continue.

IPL operates the largest and most complex crude oil pipeline system in North America, stretching over 3 700 kilometres from Edmonton, Alberta to Montreal, Quebec. The system transports many different grades of petroleum, including petroleum products, natural gas liquids and light, medium and heavy crude oils.

IPL delivers to locations in the Prairie provinces and to refining centres in Sarnia, Toronto and Nanticoke, Ontario; Montreal, Quebec; the Minneapolis-St. Paul area of Minnesota; Superior, Wisconsin; the Chicago area of Illinois and Indiana; Detroit, Michigan; Toledo and Canton, Ohio; and the Buffalo, New York area.

During 1990, average throughput on the IPL system was about 217 thousand cubic metres per day, with deliveries to domestic markets at 129 thousand cubic metres per day and deliveries to export markets at 88 thousand cubic metres per day.

The Portland-Montreal pipeline transports offshore crude oil from South Portland, Maine to Montreal, Quebec. The system currently has

Table 7-10

Light Crude Oil Requirements and Domestic Supply for Ontario

(Thousands of Cubic Metres per Day)

	1991	1992	1993	1994	1995	2000	2005	2010
Total Ontario Feedstock Requirements	**84.0**	**84.7**	**85.6**	**86.4**	**87.2**	**90.6**	**93.5**	**99.0**
Less: Domestic Supply other than Light Crude								
Heavy Crude	(10.4)	(10.5)	(10.7)	(10.7)	(11.6)	(12.9)	(14.3)	(16.2)
Partially Processed Oil	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)	(3.4)
Gas Plant Butanes	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Ontario Requirements for Light Crude	**69.9**	**70.5**	**71.2**	**71.9**	**71.9**	**74.0**	**75.5**	**79.1**
Total Available Domestic Light Crude Supply [a]	184.6	175.0	172.4	171.9	165.7	141.3	145.5	149.9
Less: Supply for Quebec	(5.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Supply for Prairies	(57.9)	(57.6)	(57.9)	(58.1)	(58.1)	(58.4)	(59.5)	(60.2)
Supply for B.C.	(14.1)	(14.5)	(15.0)	(15.3)	(15.6)	(17.3)	(19.2)	(20.9)
Minimum Exports	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)
Domestic Light Crude Supply Available for Ontario	**87.6**	**82.9**	**79.6**	**78.4**	**72.0**	**45.6**	**46.9**	**48.9**
Surplus(+) or Shortfall (-)	**17.7**	**12.4**	**8.4**	**6.5**	**0.2**	**(28.4)**	**(28.7)**	**(30.2)**

Note: [a] Includes supply from western Canada and the Mackenzie/Beaufort.

Sources: Appendix Tables A7-15 and A7-16.

a capacity of about 39 thousand cubic metres per day, which compares with a Montreal refinery capacity of approximately 30 thousand cubic metres per day.

With the projected commencement of production in the Beaufort Sea in 2004, we have assumed that a pipeline will be constructed from this area through the Mackenzie Valley to connect with the Rainbow system in northern Alberta and thus to existing main trunk line systems.

Table 7-10 illustrates the increasing light crude oil requirements of Ontario refiners. From a level of about 71 thousand cubic metres per day in 1990, Ontario's light crude oil needs are expected to grow to approximately 74 thousand cubic metres per day by 2000 and 79 thousand cubic metres per day by 2010. As a consequence of the declining availability of domestic light crude oil feedstocks throughout the review period, however, Ontario refiners will likely require imported supplies by about 1993 or 1994. Dependence on foreign feedstocks is projected to be about 28 thousand cubic metres per day by 2000, when imports would represent 38 percent of Ontario's light crude oil requirements.

The major factors influencing the timing of the need for imported feedstock supplies in Ontario include the growth in petroleum product demand, the decline in domestic light crude oil supply and, perhaps most significantly, the level of continuing light crude oil exports. If, for example, these exports dropped from current levels of about 45 thousand cubic metres per day to only 30 thousand cubic metres per day, instead of to 20 thousand cubic metres per day, imports could be required as early as 1992, depending on the availability of particular grades of light crude. On the other hand, if exports decreased to ten thousand cubic metres per day, imports might not be required until 1995 or beyond.

Ontario's growing light crude oil requirements could be met by increased imports through the Portland-Montreal system, in conjunction with a reversal of the Sarnia-Montreal pipeline. Alternatively, limited volumes of foreign crude could be shipped from the U.S. Gulf Coast to Chicago via the Capline and Chicap pipelines or through other systems and then to Ontario on the Lakehead portion of IPL. The supply option selected will depend on the magnitude of the volumes to be imported, the availability and assurance of pipeline capacity, the maintenance of batch integrity and the cost of transporting the foreign crude oil into Ontario.

The Portland pipeline can accommodate an increase in deliveries from 39 thousand cubic metres per day to about 60 thousand cubic metres per day almost immediately, for minimal investment. Further expansion to 95 thousand cubic metres per day by approximately 1996 would be possible for a relatively small additional expenditure. The current capacity of the Sarnia-Montreal line is 45 thousand cubic metres per day and the cost of reversing the line is estimated at some $C 35 million. If needed, the system could be expanded to approximately 65 thousand cubic metres per day for an additional $C 25 million. Taken together, these expansions to the two pipeline systems would enable Montreal refiners to import their requirements of about 30 thousand cubic metres per day and provide Ontario refiners with the flexibility to import up to 65 thousand cubic metres per day.

The U.S. Gulf route is currently operating near capacity, and incremental capacity would likely be expensive to build. For this reason, it appears that it could be less expensive to import light crude through Portland and a reversed Sarnia-Montreal pipeline, depending on the throughputs and tolls of a reversed line. The decision as to the need for and timing of a reversal of the Sarnia-Montreal pipeline will depend on industry's assessment of various strategic, commercial and operational factors.

7.5 Concluding Comments

In this chapter we have described our crude oil and equivalent supply projection and have discussed the implications of this outlook for domestic refiners and crude oil pipeline systems. We have focussed on a control case projection but recognize that there are many uncertainties related to this projection. Perhaps the most important of these is the crude oil price path; for this reason we have conducted high oil price and low oil price sensitivity tests which show the impact of alternative crude oil price projections on our supply outlook. In addition to crude oil price, there are a number of other uncertain parameters, including the size of the resource and the pace of technological change, which could substantially influence the outlook for crude oil supply.

The supply of light crude oil and equivalent declines initially, but is expected to increase after 1995 and to stabilize at a level of about 190 thousand cubic metres per day toward the end of the projection period.

Conventional light crude oil from the WCSB is perhaps the least uncertain of the supply sources included in our projection. It currently accounts for more that half the total crude oil supply but declines at an annual average rate of 4.5 percent over the projection period. Conventional light crude oil exploration and development in the Basin is relatively mature and the resource base has been fairly well-defined. Although we have accounted for recent technological advances such as horizontal drilling in our projections, a large proportion of the oil-in-place is unlikely to be recovered using known technologies. Technological advances in recovery techniques could improve supply relative to our projections.

Other significant components of the projected light crude oil supply include synthetic crude oil production from integrated mining plants or upgraders and supply from the frontier regions. These projects generally have relatively high supply costs and will require growth in prices in real terms and/or technological change to reduce costs in order to become economically viable over the projection period. In our control case projection, the frontier and synthetic supply in 2010 is about four times the 1990 level and these supply sources will make up more than 50 percent of the total light crude supply in 2010, up from 20 percent in 1990. Fiscal assistance by governments could influence the timing and scope of these projects.

The net available supply of blended heavy crude oil (i.e. net of upgrader feedstock) remains at approximately the current level during the initial years of the projection period and increases thereafter.

The supply of conventional heavy crude oil declines at an average rate of approximately one percent per year over the projection period in the control case. This projection is rather bullish, reflecting recent production performance and the view that horizontal drilling could have an important impact on supply over the study period.

We anticipate substantial growth in bitumen production, with supply more than three times its 1990 level in 2010. Canada's bitumen resource is very large and well-defined and the growth in bitumen production is primarily dependent on price and market growth. Upgrading in Canada is expected to remain a very marginal investment opportunity and bitumen development will therefore continue to be largely dependent on markets in the U.S. northern tier and to a lesser extent on more competitive offshore markets. Given the uncertainties related to prices and markets, there may well be more downside than upside potential in our projection of bitumen supply.

Overall, our control case outlook indicates that Canada's crude oil and equivalent supply remains relatively stable over the projection period. Supply is projected to be 10 percent lower in 1995 and 16 percent higher in 2010 than it was in 1990. While the total supply of crude oil and equivalent is projected to change only modestly, the quality of the crude oil and the regional distribution of supply changes considerably. Heavy crude oil comprises an increasing proportion of the total supply, while light crude oil supply from Western Canada becomes relatively less significant, and the importance of frontier supply increases over the projection period.

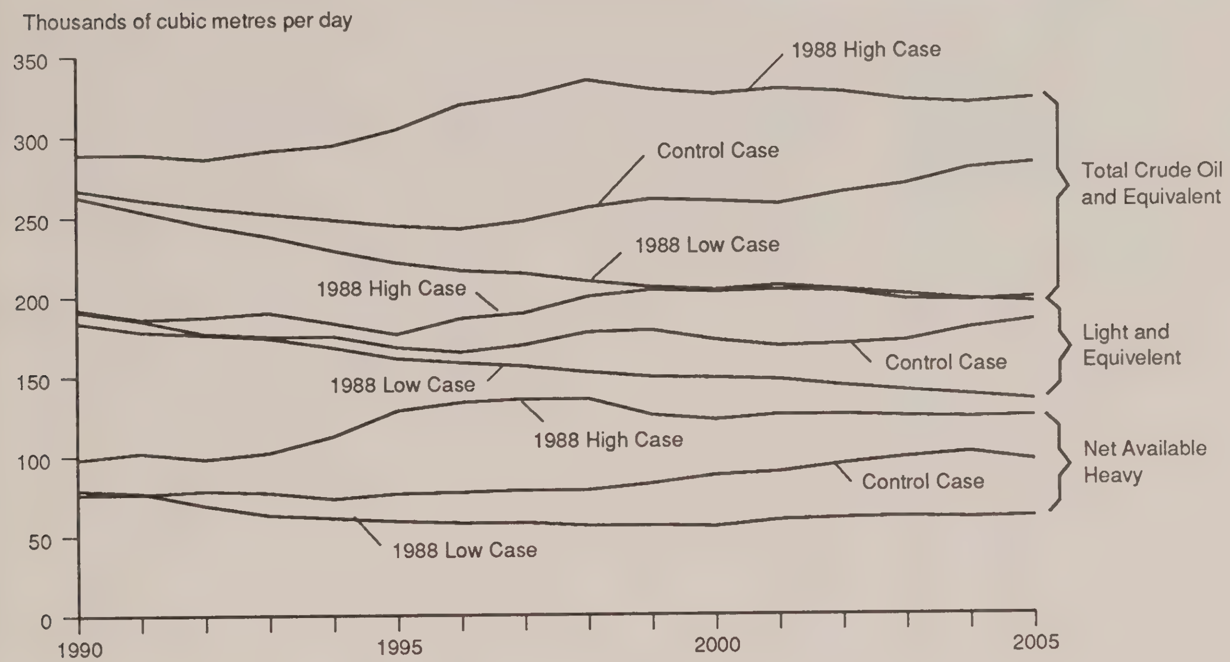
Our oil price sensitivity tests indicate that the supply projection is quite sensitive to the range of crude oil prices used, particularly in the longer term. Relative to the control case, the crude oil and equivalent supply projection is 23 percent higher and 55 percent lower in 2010 for the high oil price sensitivity case and low oil price sensitivity case, respectively. The outlook for frontier, synthetic crude oil and bitumen supply is particularly sensitive to the crude oil price outlook.

Our control case crude oil and equivalent supply projection is very similar to the low case from our 1988 Report during the early portion of the projection period, but thereafter moves gradually toward the high case of the 1988 Report, reaching 87 percent of the high case in 2005 (Figure 7-23). Light crude oil and equivalent supply in the control case projection reaches 93 percent of the high case projection for 2005 in the 1988 Report, whereas net available blended heavy supply is 79 percent of the volume projected for 2005 in the high case of the 1988 Report.

As in the 1988 Report, the contribution of heavy crude oil supply, particularly bitumen, and frontier supply increases and conventional light crude oil supply from the WCSB declines over the projection period. This has certain implications for the crude oil transportation system and refinery configuration in Canada. In our control case outlook, the crude oil supply in Alberta, available to IPL, will be about the same in 2010 as it was in 1990, however, the supply mix will be considerably heavier. Light crude oil shipments from Western Canada to Montreal via the Sarnia - Montreal segment of the IPL system have recently ceased. As light crude oil supply

Figure 7-23

Productive Capacity of Crude Oil and Equivalent (Comparison with Results of 1988 Supply/Demand Report)



from the WCSB continues to decline, it will be necessary for Ontario refiners to examine their supply options, one of which would be to reverse the Sarnia - Montreal line to allow imported light crude oil to be shipped to Sarnia via Portland, Maine. The decision as to the need for and timing of a reversal of the Sarnia - Montreal pipeline will depend on industry's assessment of various strategic, commercial and operational factors.

We anticipate that over most of the projection period the growth in domestic demand for petroleum products can be met by increased utilization of existing domestic refinery capacity, together with some modest debottlenecking done in conjunction with anticipated investments necessary to meet more stringent environmental standards. In total the requirements for crude oil in Canada are expected to increase from 261 thousand cubic metres per day in 1990 to 294 thousand cubic metres per day in 2010.

Our control case supply projection exceeds domestic crude oil demand throughout the projection period and Canada therefore remains a net exporter of crude oil and equivalent. We anticipate, however, increasing volumes of light crude oil imports to satisfy refinery feedstock requirements in the Maritimes, Quebec and Ontario and exports of large volumes of heavy crude oil produced in Western Canada and light crude oil produced from the East Coast offshore, primarily to the U.S. Some light crude oil from Western Canada is also anticipated to be exported throughout the projection period.

Security of supply is a consideration for regions of Canada that are dependent on imported oil for a significant portion of their energy requirements, as supply disruptions may have negative consequences for these regions. Our analysis in this study focuses on longer-term supply and demand trends. The timing and magnitude of any supply disruptions which

might occur from time to time over the projection period cannot be projected with any certainty and we make no attempt to do so in our analysis. Thus far, disruptions have been of a temporary nature. The short-term effects of supply disruptions can be mitigated by various means and this issue has been discussed to some extent in the Board's recently released Sarnia-Montreal Pipeline report.[1] Our current study is a long-run analysis and we have no reason to think disruptions would be of an enduring character. Rather we would expect that over the long run, market forces would cause prices to respond, encouraging additional oil production, energy conservation, supply diversification and the use of competing or alternative fuels.

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1 *The Sarnia-Montreal Pipeline - A Review and Report by the National Energy Board*, April 1991.

Chapter 8

Natural Gas Liquids

In this chapter we examine the contribution of natural gas liquids (NGL) - ethane, propane, butanes and pentanes plus - to the supply of and demand for energy in Canada. We begin with an overview of the Canadian NGL production and transportation infrastructure. This is followed by a discussion of domestic NGL demand. We then review NGL supply from natural gas plants and crude oil refineries. A discussion of exports and supply/demand balances for each of ethane, propane and butanes is then provided.[1] We conclude the chapter with a summary of the major findings and observations arising from the analysis and of the principal uncertainties inherent in our projections.

8.1 Overview of the Canadian NGL Production and Transportation Infrastructure

This section provides an overview of the natural gas liquids extraction and processing facilities in Canada and of the pipeline systems which transport liquids to domestic and export markets.

8.1.1 Extraction and Processing Facilities

Production of natural gas liquids is primarily associated with the processing of natural gas, but propane and butanes are also produced at crude oil refineries.

Natural gas, as produced in its natural state, normally contains a large quantity of methane, along with varying amounts of heavier hydrocarbons (natural gas liquids) including ethane, propane, butanes and pentanes plus. It often also contains non-hydrocarbons such as carbon dioxide, nitrogen, and hydrogen sulphide.

In order to meet pipeline specifications, most natural gas requires some processing at field gas plants. This generally involves removal of some of the heavier hydrocarbons in order to prevent condensation of liquids in gas pipelines. In addition to the extraction of liquids to the extent necessary to meet pipeline specifications, there is often also an economic incentive to extract further liquids. This additional extraction occurs at both field gas plants and straddle plants (often referred to as reprocessing plants). To satisfy end use demands, the liquids which are extracted must then be split into their individual components. This occurs at some field plants which have this capability or at fractionation facilities which are designed specifically for this purpose. Field gas plants, fractionation plants and straddle plants are discussed, in turn, below.

There are close to 600 **field gas plants** currently operating in Canada. The design criteria differ from plant to plant depending on both the composition of the gas to be processed and the extent to which the gas is to be processed. Some gas plants consist of only water removal (dehydration) facilities, some have facilities to remove hydrogen sulphide and some have natural gas liquids recovery facilities. Many plants contain all of these facilities. Of the plants that have liquids extraction facilities, some remove only the heaviest of the natural gas liquids, pentanes plus. Others produce what is known as a propane plus mix, which consists of propane, butanes and pentanes plus. Other plants have the capability to extract an ethane plus mix, which differs from a propane plus mix only in that it also contains ethane.

NGL mixes produced at field plants without on-site capability to fractionate are transported to other field plants or to major **fractionation plants**. The major fractionation centre in Alberta is at Fort Saskatchewan near Edmonton, where both Chevron and Amoco operate fractionation facilities. Natural gas liquids mixes produced in Western Canada can also access fractionation facilities in Sarnia, Ontario and Marysville, Michigan.

Most gas produced in Alberta is reprocessed in **straddle plants** in order to extract further liquids which were not removed at field

1 The pentanes plus supply/demand balance is included in the total supply/demand balance for light crude oil and equivalent discussed in Chapter 7.

plants. The straddle plants in Alberta are located on the main gas transmission systems which carry gas out of Alberta or that supply the city of Edmonton. These plants are capable of removing essentially all of the propane, butanes and pentanes plus in the gas stream and about 70 percent of the ethane. They account for most of the ethane supply, but for a lesser proportion of propane, butanes and pentanes plus supply because the majority of these heavier liquids have already been extracted at field gas plants.

The vast majority of Canadian NGL supply is obtained from plants located in Alberta. In British Columbia, the major source of liquids is from processing and reprocessing plants located at Taylor in northeastern B.C. In Saskatchewan, NGL supply is obtained primarily from the Amoco-operated Steelman plant, which produces specification ethane and a propane plus mix which is transported to Sarnia for fractionation.

Propane and butanes are also components of crude oil, often amounting to between three and four percent by volume. These volumes, as well as any additional volumes produced as a by-product of later stages of the refining operation, are recovered within the refineries. Although some propane and butanes find their way into the gasoline pool or are consumed as feedstock to other refinery process units, several refineries produce volumes which are surplus to their internal needs. These volumes are included in our estimates of supply since they are sold to other refineries, petrochemical plants or other end use markets.

8.1.2 Intraprovincial, Interprovincial and Export Delivery Systems

NGL produced in Western Canada move to both export and eastern Canadian markets through two major pipeline systems originating in Edmonton - IPL and Cochin (Figure 8-1). Other smaller pipeline systems serve regional markets. As well, NGL are transported by rail and road.

In Alberta, a network of pipelines allows the movement of most NGL products from the gas plants to fractionation facilities or to storage facilities. These pipelines most often transport an NGL mix. A separate gathering system exists for specification ethane. The Alberta ethane gathering system collects specification ethane from straddle plants and from field plants which produce ethane (Figure 8-2). The primary market for the ethane in Alberta is as feedstock for the Alberta Gas Ethylene plants at Joffre near Red Deer. Ethane can also be moved to large underground storage caverns near Edmonton, from where it can be shipped, via the Cochin pipeline, to markets in the U.S. or as far east as Windsor, Ontario.

Natural gas liquids other than specification ethane, including ethane-plus mixes, are collected via another series of pipelines, some of which also transport crude oil (Figure 8-3). This system of pipelines centres around Edmonton, where both fractionation and storage facilities exist. This is also the connecting point with the IPL and Cochin pipeline systems which carry these liquids to both export and eastern Canadian markets. The Cochin system can move NGL mixes but most often carries specification products. The IPL pipeline, which is the major carrier of NGL from Western Canada, is used to transport only propane-plus mixes. In addition to Edmonton, propane-plus mixes are received by the IPL system at Kerrobert and Regina. These mixes are delivered to the Sarnia, Ontario area where they are fractionated. Onward deliveries from Sarnia are made by pipeline, rail and road transport.

Southern Saskatchewan and Manitoba NGL markets are served by the Petroleum Transmission Company pipeline from Empress, Alberta to Winnipeg, Manitoba.

To cope with the seasonal nature of the supply and demand for propane and butanes[1], large underground storage caverns have been developed. These facilities are concentrated in Alberta and Saskatchewan and in the Sarnia-Windsor, Ontario area at points close to the main pipeline systems (Figure 8-1).

The U.S. Midwest, Canada's main export market, is served by an existing pipeline and storage infrastructure. This market lends itself well to Canadian-sourced supplies because, unlike the U.S. Atlantic and Gulf Coast markets, it is more difficult to serve with offshore supplies. Propane originating in Alberta is transported to U.S. Midwest markets via the Cochin and MAPCO pipeline systems. In addition, NGL mixes transported via the IPL system and fractionated in Sarnia, Ontario are exported to U.S. customers

1 Demand for propane and butanes in heating markets and for gasoline blending is higher in the winter months than in the summer months. To meet this seasonal demand, propane and butanes are put into storage in the summer months for use during peak winter demand.

Figure 8-1
NGL Interprovincial and Export Delivery Systems

Figure 8-2

Alberta Ethane Gathering System

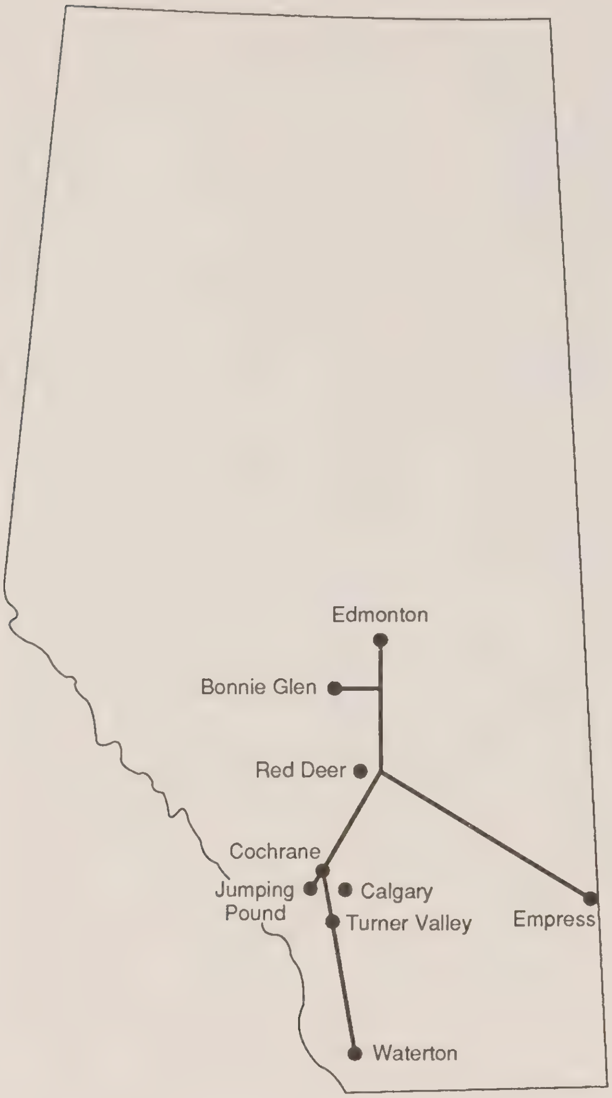
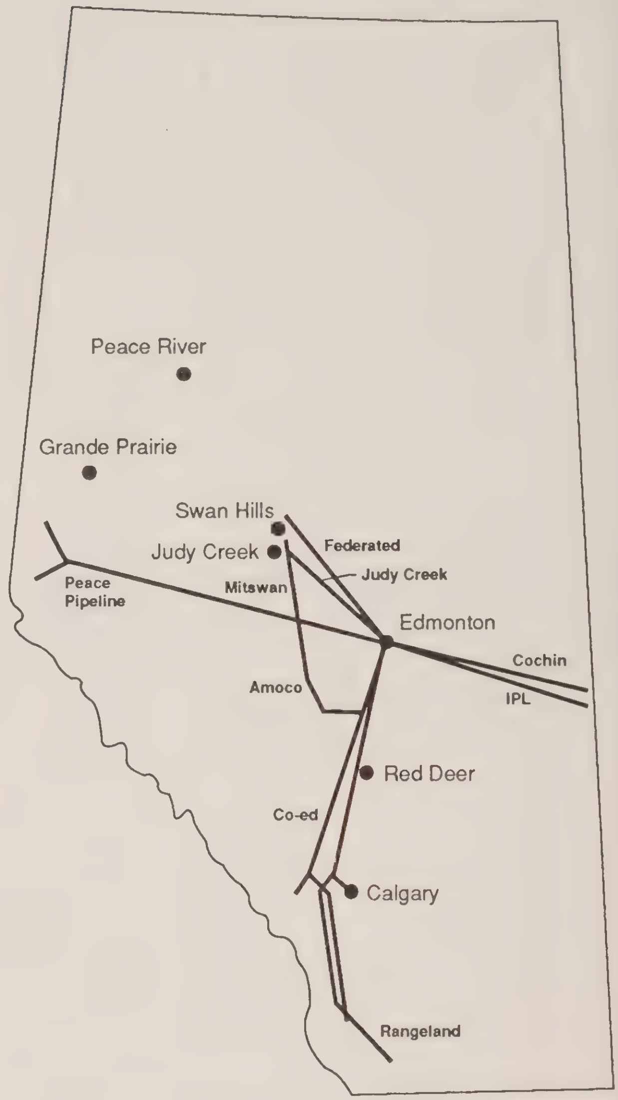


Figure 8-3

Alberta NGL Gathering System



located in the Midwest and North Central and North Eastern U.S. An integral part of the IPL capability to move NGL east is the storage capacity at Superior, Wisconsin. Several storage spheres are being upgraded to handle higher vapour pressure NGL and the capability to remove propane from the NGL stream and a truck loading facility are also being added. This will allow propane markets in this area to be served. Western Canadian supplies destined for export from Eastern Canada are supplemented with propane and butanes produced at eastern Canadian refineries.

8.2 Domestic Demand

NGL have a wide variety of uses in Canada, with distinct markets for each of ethane, propane and butanes. This section provides a review of the end use demand for NGL which was discussed in Chapter 4. In addition, it describes other NGL requirements, including demand for miscible floods and butanes used in refineries, which contribute to the total domestic demand for NGL.

Since the construction of the first world-scale ethylene plant in Alberta in 1978, **ethane** has been an important petrochemical feedstock. A second plant was constructed in 1984. Our projections include a third ethylene plant commencing operations in 1995,

with a subsequent expansion in 1998. Petrochemical demand for ethane is projected to grow from the current 18 thousand cubic metres per day to over 27 thousand cubic metres per day by 2010.

Ethane is also used for enhanced oil recovery. As Figure 8-5 shows, the use of ethane in enhanced oil recovery has increased appreciably since 1984 with the start-up of several miscible flood projects; it currently accounts for about 65 percent of the NGL used in miscible floods. Ethane requirements for miscible floods are projected to decline over the projection period as a limited number of new miscible flood projects are expected to be implemented. Toward the end of the period there is a small increase in demand as increased oil prices stimulate increased EOR activity. In the medium to longer term, ethane demand is dominated by petrochemical requirements.

Traditional markets for **propane** have included residential space heating, agricultural uses such as crop drying and powdered milk production, restaurant fuel in the commercial sector, portable heating in the industrial sector, and use as a solvent for enhanced oil recovery. Since the late 1970s, larger volumes of propane have been used as a petrochemical feedstock. During the early 1980s a market also developed for propane as a road transportation fuel.

We project propane demand to increase in all end use sectors, but particularly in the transportation and petrochemical sectors. Demand in the transportation sector increases from 2.8 thousand cubic metres per day in 1989 to 4.2 thousand cubic metres per day in 2010. Over the same period, petrochemical demand increases from 1.6 thousand to 3.1 thousand cubic metres per day. Propane requirements for miscible floods decline from over 3 thousand cubic metres per day in 1991 to 0.5 thousand cubic metres per day in the late 1990s, before climbing to 1.2 thousand cubic metres per day by the end of the projection period (Figure 8-6).

Butanes are used primarily as a refinery feedstock but are also used as petrochemical feedstocks and to a very limited extent for space heating. Butanes are seldom used in miscible floods, except when they are entrained in NGL mixes.

The major factor influencing refinery demand for butanes is motor gasoline production. Refinery demand for butanes is dominated by demand in Alberta and Ontario. Gasoline production increases by approximately 5 percent in Alberta over the projection period and by over 12 percent in Ontario. We assume that because most refineries blend the maximum volumes of butanes permitted in gasoline, changes in the demand for gasoline lead to corresponding changes in the demand for butanes. Refinery requirements for butanes remain at a level of about three thousand cubic metres per day throughout the projection period.

Petrochemical demand for butanes increases over the projection period from 1.5 thousand to 3.6 thousand cubic metres per day. The first methyl tertiary butyl ether (MTBE) plant in Canada is expected to be on production in late 1991 and will result in an incremental feedstock demand for butanes of 1.8 thousand cubic metres per day. We anticipate that all MTBE production from this plant will be exported. However, if this MTBE were blended in gasoline in Canada to increase octane, it would lead to a reduction in the demand for butanes for direct use in motor gasoline production.

The demand for butanes as a miscible fluid is projected to fall from 1.3 thousand cubic metres per day in 1990 to 0.3 thousand cubic metres per day by 1994 and remain at very modest levels over the duration of the projection period (Figure 8-7).

8.3 Supply

In this section we describe the basis for our projections of NGL supply, first from natural gas plants and then from crude oil refineries.

Estimates of NGL reserves for Alberta and British Columbia published by the ERCB and the B.C. Ministry of Energy, Mines and Petroleum Resources, respectively, are shown in Table 8-1. We have not developed our own estimates of NGL reserves and the estimates shown are not consistent with the Board's estimates of natural gas reserves presented in Chapter 6.

Our projections of NGL supply from gas plants are influenced primarily by two factors: these are our projection of future liquids yields and our projection of total natural gas production.

The liquids yield is a measure of the cubic metres of NGL recovered per million cubic metres of natural gas production. Throughout the 1960s and early 1970s, yields of propane, butanes and pentanes plus were increasing (see Figure 8-4). This is attributable to a number of factors:

- implementation of large gas cycling schemes in condensate reservoirs in order to maximize liquids recovery;

Table 8-1

Natural Gas Liquids Reserves Provincial Estimates

(Millions of Cubic Metres)

	British Columbia[a]	Alberta[b]
Ethane	-	330.0
Propane	N/A	129.4
Butanes	N/A	73.1
Pentanes Plus	5.1	123.5
LPG[c]	10.7	N/A

Notes: [a] Source: Hydrocarbon and By-Product Reserves in British Columbia, 1989, B.C. Ministry of Energy Mines and Petroleum
[b] Includes volumes recoverable from field gas plants, reprocessing plants and solvent floods. Source: ERCB ST90-18 Alberta's Reserves of crude oil, oil sands, gas, natural gas liquids, and sulphur.
[c] Propane and butanes.

- increases in crude oil demand and growth in domestic crude oil production expanded the supply and processing of NGL - rich solution gas; and
- construction of gas reprocessing facilities (straddle plants) at Empress in 1964, at Cochrane in 1970, and at Empress again in 1971 increased the recovery of liquids over that obtained from field processing plants.

However, by the mid-1970s the yields of these liquids began to decline as a result of declining production from the large gas cycling schemes in Alberta. The yield of pentanes plus was most affected because much of the supply had historically been provided by these schemes. From 1975 to 1985 the yields of propane, butanes and pentanes plus in Alberta declined by 17, 27 and 42 percent, respectively. From 1985 to 1989 the yield of propane increased slightly, the yield of butanes was essentially unchanged and the yield of pentanes plus further declined. As yields of propane, butanes and pentanes plus began to decline in the 1970s, the extraction of ethane was just beginning. The yield of ethane continued to increase until the last half of the 1980s, as extraction facilities were added and expanded at straddle plants and were also added at field gas processing plants to meet the demand for liquids for enhanced oil recovery. The addition of ethane recovery facilities at straddle plants also resulted in an increase in the recovery of propane at these facilities.

Our projection of future liquids yields is determined by the projected liquids content of natural gas produced over the projection period and by the extent to which the liquids produced in the natural gas stream are expected to be extracted at field plants and reprocessing facilities. Given a projection of the liquids yield, the total NGL supply projection is obtained by applying the projection of liquids yields to the overall level of natural gas production.

To estimate the liquids content of natural gas to be produced over the projection period, we examined trends in the liquids content of gas reserves discovered through time, the liquids content of currently non-producing gas reserves and estimates of the liquids content of future reserves additions developed by the ERCB.

In reviewing the liquids content of gas discovered through time in Alberta, we observe a trend to slightly drier gas discoveries from the early 1950s through to about 1975, as evidenced by lower percentages of ethane, propane and butanes in the gas composition. However, there is a reversal in this trend over the last 15 years, with the quantities of ethane, propane and butanes contained in gas discoveries increasing by 50 percent or more from the level of the early 1970s. Gas reserves discovered during the 1970 to 1985 period generally contained less pentanes plus than the historical average. However, the pentanes plus content of gas discovered over the last five years has been about 50 percent higher than the average through time.

We have considered two categories of non-producing gas reserves: associated gas, for which sales are deferred because the gas is required for pressure maintenance in order to maximize oil recovery; and, non-associated gas, which is not being produced because of a lack of markets or poor economics.

Associated gas, which currently accounts for about 10 percent of total gas production, is generally rich in liquids and increased production of this gas tends to increase the overall liquids content of the produced gas stream. In our projections, associated gas reserves are brought on stream in a phased manner which results in the associated gas production remaining essentially constant over the projection period. Shut-in non-associated gas reserves are brought onstream progressively, with 90 percent onstream within the first six years of the projection and 100 percent within 10 years. By the year 2000, this gas makes up over 30 percent of total gas production. This gas contains only about one-half the average quantity of liquids initially contained in gas discovered to date and therefore tends to decrease the overall NGL content of the gas stream when brought on production.

In comparing the average initial NGL content of gas discoveries to date with current NGL yields, we observe that the former is considerably higher (by about 30 percent). The lower current yields can be attributed to the fact that many of the gas pools initially rich in liquids have been depleted through cycling schemes, gas pools initially rich in liquids are at a more advanced stage of depletion than dry gas pools because they have been produced preferentially in view of their more attractive economics, and not all liquids are being recovered from produced gas.

With respect to reserves additions, the ERCB estimates that natural gas will contain 75, 45 and 85 cubic metres of liquid propane, butanes and pentanes plus, respectively, per million cubic metres of marketable gas. These levels are similar to those currently being extracted in Alberta. These estimates were derived by dividing Alberta into geologically similar areas, determining the NGL content of gas found to date in each of these areas, and assuming that future discoveries in each of these areas would have compositions resembling those which have been made to date. We have taken account of these estimates in preparing our projections.

In addition to the projections of the liquids content of natural gas expected to be produced, our projection of future liquids yields is determined by our projection of recovery levels.

Gas plant operators often have an economic incentive to extract liquids beyond the minimum level necessary to meet pipeline specifications. The profitability of liquids extraction is influenced by a number of factors, including:

- the value of natural gas at the plant gate;
- the value of natural gas liquids at the plant gate;
- the availability of markets; and
- the cost of extracting the natural gas liquids.

Taken together, these factors will largely determine the extent to which liquids available to be recovered are in fact extracted at gas plants over the projection period.

Relative prices of crude oil and natural gas are an important consideration when evaluating the profitability of natural gas liquids extraction, largely due to the manner in which plant gate prices for NGL are determined. Natural gas liquids are substitutable in various end use markets with crude oil products. The price of crude oil directly influences the price of refined products and, to the extent that refined products and NGL are substitutable, therefore indirectly influences the price of NGL in end use markets. Plant gate prices for NGL are equal to the end use market price less transportation and distribution charges. At the gas plant the incentive to extract NGL, beyond the minimum level necessary to meet pipeline specifications for natural gas, is driven by the value of NGL relative to the value of natural gas at the plant gate. The value of NGL must exceed that of natural gas by an amount at least sufficient to cover the costs of extraction. In our control case the price of natural gas increases relative to that of crude oil over the projection period. This would have the effect of reducing the value of NGL at the plant gate relative to natural gas, thereby reducing the economic incentive for NGL extraction.

Although we anticipate that the change in relative price over the projection period would have this directional impact, we have not attempted to quantify the effect on our NGL supply projections. The economics of NGL extraction differ significantly from gas pool to gas pool, depending on such factors as natural gas sales contracts, the liquids content of the gas stream and the existence and ownership of a suitable gas processing plant; a rigorous analysis incorporating these considerations is beyond the scope of this study. Rather, we have assumed that future NGL recovery levels will be similar to those which currently exist; essen-

tially all of the propane, butane and pentanes plus is currently recovered and approximately one-half of the ethane available to be extracted is recovered. Our supply projections therefore represent the potential supply availability, unconstrained by demand, given these projected recovery levels from the produced gas stream. To the extent that the economic incentive to extract liquids diminishes over the projection period, the actual supply which becomes available may be lower than that which we have projected.

We have also prepared projections of NGL supply for selected gas plants which comprise about 95, 75, 75 and 60 percent of current production of ethane, propane, butanes and pentanes plus, respectively. These projections were used to assist us in developing the overall projections of NGL supply for the period to 2010. For these plants, the average liquids content of the inlet gas streams is projected to increase in the 1992-1993 period when the Shell Caroline plant is expected to come onstream and does not change significantly thereafter (Appendix Tables A8-3 to A8-6).

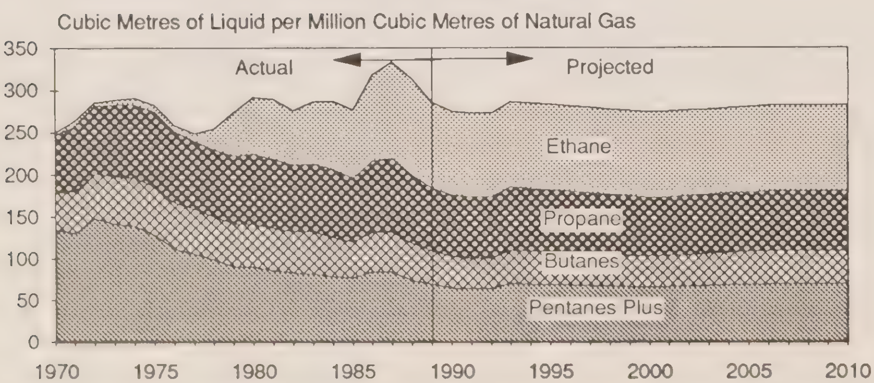
The considerations outlined above form the basis for our projections of future natural gas liquids yields. Overall, we expect that liquid yields will decline in the short term as liquids in existing cycling schemes are depleted and as the production of non-associated natural gas increases to meet increased overall demand for natural gas. However, the natural gas discovery at Caroline in Alberta, which is rich in gas liquids, is expected to start production in late 1992 and reach maximum production by 1993. Production of liquids from this field is expected to result in an increase in the overall yield of gas liquids. We have assumed that the yield will again begin to decline after 1993 as a result of increased production of non-associated gas, reduction in liquids production from cycling schemes and depletion of some of the richer gas pools. Throughout the projection period, natural gas supply from reserves additions comprises a progressively larger portion of total natural gas production. This leads to a slight increase in the overall yield beyond the year 2000. The changes in liquids yields relative to current levels are projected to be relatively modest. For propane, butanes and pentanes plus, yields in Western Canada are projected to remain within 5 percent of current levels. Ethane yields are projected to remain virtually constant. Historical and projected yields are shown for each NGL component in Figure 8-4.

Given the projections of yields (the volume of NGL recovered per unit of natural gas production), the total production of NGL from western Canadian gas plants is then directly related to the total volume of natural gas produced. Natural gas production from Western Canada is projected to increase by about thirty percent between 1989 and 2001, after which a modest decline is anticipated. In 2005, natural gas production from Western Canada is projected to be about 15 percent higher than in the high case in our 1988 report.

In addition to the WCSB, natural gas production from the Mackenzie Delta and from the East Coast offshore is expected to contribute to the supply of NGL by 2010.

We expect that Mackenzie Delta gas will be processed to recover pentanes plus, as was indicated by Esso, Gulf and Shell in the Board's GH-10-88 hearing into gas exports from the Mackenzie Delta. Production of pentanes plus from the Delta is projected to begin at 3000 cubic metres per day and subsequently increase to 4000 cubic metres per day when Delta gas production increases late in the projection period.[1] We have

Figure 8-4
NGL Yields
Control Case



1 Due to the relative timing of our analytical work on NGL and natural gas supply, there is a minor inconsistency between the year of commencement of Delta gas production in this chapter (2002) and in chapter 6 (2004). Given the uncertainties in the scheduling of frontier projects, we consider the discrepancy to be minor.

assumed that the incremental gas production will not be as rich in pentanes plus as the initial gas production. Transportation of these liquids to markets would require construction of a pipeline from the Mackenzie Delta. We anticipate that further extraction of liquids from the Delta gas will occur in one of the straddle plants in Alberta.

East Coast offshore gas production is projected to commence in 2010 (see Chapter 6) at a level of 125 petajoules per year. Production of propane, butanes and pentanes plus corresponding to this level of natural gas production is projected at 400, 300 and 1300 cubic metres per day, respectively. There is no ethane production projected from East Coast gas.

The result of our analysis with respect to current and future NGL yields, natural gas production from the WCSB and frontier natural gas projects is that NGL supply from gas plants increases throughout the projection period (Table 8-2, Appendix Table A8-2).

Propane and butanes (LPG) are also produced at oil refineries during various stages of the refining process. Crude oil entering refineries can contain as much as four percent LPG by volume. LPG are separated along with light gases from the other components of the crude oil stream at the beginning of the refining process and are also produced as a by-product of later stages of the refining operation.

Table 8-2

Supply of Natural Gas Liquids
Control Case

(Thousands of Cubic Metres per Day)

	1989	1993	2000	2005	2010
Gas Plants					
Ethane	28.1	34.1	38.0	41.2	41.5
Propane	21.0	25.4	26.0	28.2	28.4
Butanes	11.2	13.3	13.9	15.7	16.0
Pentanes Plus	19.5	23.8	24.3	27.6	27.9
Refineries					
Ethane	-	-	-	-	-
Propane	4.5	4.6	4.8	5.0	5.1
Butanes	2.0	2.1	2.2	2.2	2.3
Pentanes Plus	-	-	-	-	-
Total					
Ethane	28.1	34.1	38.0	41.2	41.5
Propane	25.5	30.0	30.8	33.2	33.5
Butanes	13.2	15.4	16.1	17.9	18.3
Pentanes Plus	19.5	23.8	24.3	27.6	27.9

Source: Appendix Table A8-2.

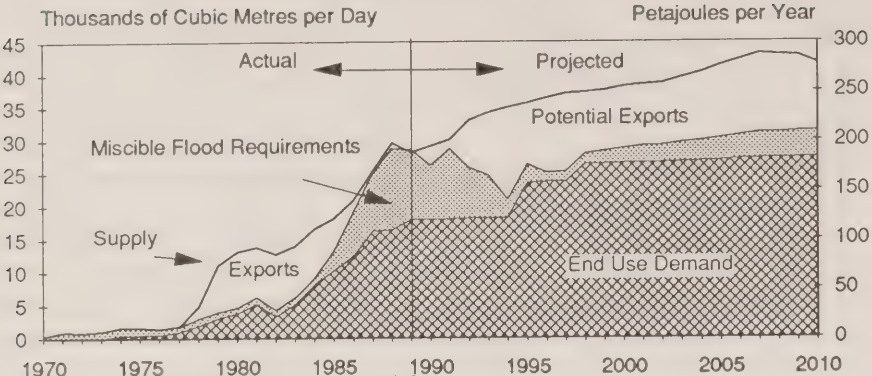
Once recovered in a refinery, LPG is either marketed, consumed as fuel, used as feedstock to other processing units, or in the case of normal butane, blended with gasoline. The projections are based on the volumes of LPG sold by refineries per unit of crude oil feedstock on a regional basis in 1989 and on the projections of crude oil feedstock requirements discussed in Chapter 7. Although we recognize that the volume of refinery LPG marketed may change as the quality of crude oil refined in Canada varies or as refinery configurations are altered to meet changing product demands, our projections do not account for these factors.

We expect refinery production of propane and butanes to increase modestly throughout the projection period (Table 8-2). The projections of propane and butanes supply from refineries are shown by region in Appendix Tables A8-7 and A8-8, respectively.

Our supply projections do not include any production of NGL from synthetic crude oil or upgrading plants. Currently the synthetic gases generated in the upgrading processes at these plants along with any liquids they contain are used as plant fuel. Plant owners have studied the recovery of NGL from synthetic gases but to date have not found it to be economically viable. We assume that the new synthetic oil and upgrading plants included in our projections will not include natural gas liquids recovery units.

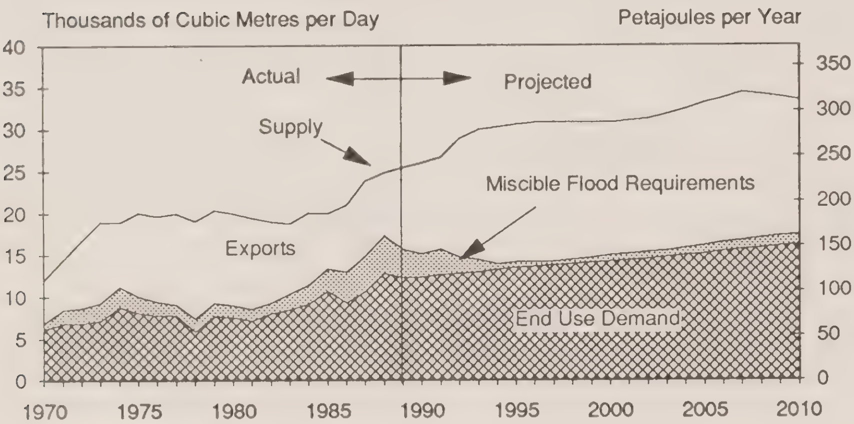
Our projections of total ethane, propane and butanes supply are shown in Figures 8-5, 8-6 and 8-7, respectively.

Figure 8-5
Ethane Supply and Demand
Control Case



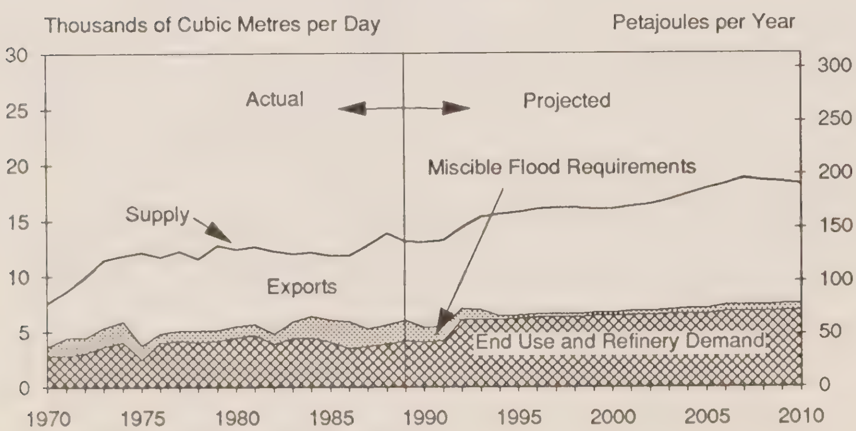
Source: Appendix Tables A8-1 and A8-9.

Figure 8-6
Propane Supply and Demand
Control Case



Source: Appendix Tables A8-1 and A8-10.

Figure 8-7
Butanes Supply and Demand
Control Case



Source: Appendix Tables A8-1 and A8-11.

8.4 Exports and Supply/Demand Balances

In this section we describe the relationship between supply and domestic demand for each of ethane, propane and butanes and potential exports for each product.

Domestic ethane demand increases by 20 percent over the projection period. However, a potential increase of over 40 percent in the supply of ethane could provide opportunities for increased export levels over those anticipated for 1991. Ethane from Western Canada is currently being exported via the Cochin system to U.S. Midwest and Gulf Coast markets. Ethane exports in 1990 averaged about 4 thousand cubic metres per day and reach between 5 and 6 thousand cubic metres per day in 1991. In the longer run, if markets for surplus ethane cannot be found, it will be reinjected into the gas stream.

End use demand for propane has been increasing steadily since the late 1970s. Our projections show this trend continuing, mainly due to growth in petrochemical and transportation uses. However, requirements for propane for hydrocarbon miscible floods are projected to decline. Overall, demand for propane decreases in the short term as a result of declining miscible flood demand but steadily increases from 1995 through to the end of the projection period. Supply is projected to increase more than domestic demand, resulting in increasing surpluses of propane available for export.

Demand for butanes has been relatively stable since the early 1970s, at levels far below those of

supply. Our projections show end use plus refinery requirements for butanes continuing to be relatively stable, but requirements for miscible floods declining in the 1990s. The supply of butanes is projected to increase, leading to an even greater excess of supply over domestic demand than has been experienced in the past.

The United States currently represents Canada's main export market for propane and butanes. Canada exported propane to Japan in the past, but no longer does so because Middle East and other Pacific Rim countries have a competitive advantage. On the U.S. Gulf Coast, where increased competition is expected from Algerian and Middle East-sourced supplies, Canadian propane is today competitive owing to incentive tariffs on both the Cochin and the MAPCO systems.

8.5 Concluding Comments

Canada has an extensive and well-developed infrastructure for NGL production, transportation and distribution.

Domestic demand for NGL is expected to increase despite reductions in the demand for NGL for use in miscible flood projects. Domestic demand for ethane is projected to increase as a result of the construction of a new ethylene plant. Propane demand is projected to rise in all sectors, with the most significant increases being in the transportation and petrochemical sectors. Completion of an MTBE plant currently under construction leads to an increase in butanes demand.

NGL supply is obtained primarily from natural gas processing but some propane and butanes is produced at crude oil refineries. The main determinants of potential supply are liquids yields and natural gas production.

We anticipate that liquids yields will remain relatively constant but this depends upon a number of factors, including the composition of future natural gas discoveries, and as a result there is some inherent uncertainty in this assumption. NGL supply potential is expected to increase over the period as natural gas production increases in response to rising domestic and export demand. Overall our projections of NGL supply are up significantly from the high case projections in our 1988 report because of higher projections of natural gas production and of liquids yields. In 2005, our current projections of propane, butanes and pentanes plus supply are 30, 16 and 23 percent higher, respectively, than in the high case in our 1988 report. To the extent that natural gas production were higher or lower than projected in the control case, there would be a commensurate increase or decrease in the potential NGL supply availability.

Our supply projections are of potential supply and the incentive to extract liquids is dependent on relative oil/gas prices, among other factors. In our control case projection, gas prices rise relative to those of oil over the projection period. Although of itself this would have a negative impact on the economics of NGL extraction we still anticipate that, with increasing natural gas production, NGL supply will grow over the projection period.

Our analysis indicates that for each of ethane, propane and butanes there will be a substantial excess of potential supply over domestic demand during the projection period.

The potential supply of ethane exceeds domestic demand by a considerable amount throughout the projection period. To the extent that export markets are not available for these volumes, the ethane will be left in the gas stream and marketed as natural gas. In order to market all of the propane and butanes production, we will continue to be heavily dependent on competitive export markets. As is the case with ethane, some volumes of propane and butanes could be left in the gas stream and marketed as natural gas, if these export markets do not materialize.

Chapter 9

Coal

In this chapter, we examine the supply of and demand for Canadian coal in domestic and international markets. The chapter begins with a review of the various types of coal and the remaining resources and reserves of each type. This discussion is followed by a review of coal prices and transportation costs. Projections of domestic demand, exports, imports and production are followed by concluding comments regarding our coal supply and demand projections.

The quality of Canadian coal ranges from the lower quality lignitic and subbituminous classes to the higher quality bituminous and anthracitic coals. As coal quality increases, so too does energy content. An important characteristic of coal is sulphur content. Reduced acid gas emissions are essential to continued acceptability of coal. Increasing concern over sulphur dioxide emissions and acid rain place a premium value on western coal reserves which generally have less than one percent sulphur. Atlantic coals typically contain about four percent sulphur, with a few deposits containing ten percent or more. Coal use varies depending on the quality of the coal:

- Lignitic and subbituminous coals, which because of their low energy content are not economic to transport over long distances, are used mainly for thermal power generation close to the mine mouth.
- Bituminous coals are also used for thermal power generation and their higher quality makes it worthwhile to transport these coals to more distant markets. Some bituminous coals have properties which make them suitable for use in the production of coke, a reducing agent and heat source for the steel industry. These coals require preparation to meet market specifications, which involves, among other things, reducing the mineral matter, sulphur and moisture content.
- Small amounts of imported anthracite are used for titanium smelting. Although Canadian deposits of anthracite are not currently being exploited, they may be suitable for some thermal applications.

9.1 Resources and Reserves

Canada has a large endowment of coal.[1] Coal resources, which represent only a small portion of the total endowment, include coal deposits which occur within specified limits of thickness and depth from the surface. These limits are intended to reflect both the economic and technical feasibility of exploitation.

Coal resources are commonly divided into two main categories: resources of "immediate interest" and resources of "future interest". To be of immediate interest, resources must consist of coal seams with combinations of thickness, quality, depth and location which render them attractive for further exploration or early development. Resources of future interest would be very costly to produce because of either their remoteness or depth of occurrence. Both categories are subdivided into "measured", "indicated", and "inferred" resources, according to the amount of exploration, sampling and analysis that has been conducted. There is a high level of certainty that measured resources exist and least assurance about inferred resources.

Almost 95 percent of resources of immediate interest is located in Western Canada (Table 9-1). Resources of future interest are concentrated in the Arctic and at greater depths in the Plains region of Alberta (Appendix Table A9-1).

Over 60 percent of resources of immediate interest consists of low quality lignitic and subbituminous coal deposits located, for the most part, in Alberta. Higher quality bituminous resources of immediate interest are found mainly in British Columbia, but significant deposits also occur in Alberta and Nova Scotia.

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1 The definitions used to describe coal resources and reserves are those which are generally accepted by the coal industry. These differ somewhat from the definitions of resources and reserves commonly used by the oil and gas industry and used in preceding chapters of this report.

Table 9-1
Summary of Canada's Coal Resources of Immediate Interest by Province
(Megatonnes)

Province	low volatile bituminous - anthracite	medium-low voaltile bituminous	high - medium volatile bituminous	subituminous-high volatile bituminous	lignite - subbituminous	Total
British Columbia	1610	9270	7190	645	1090	19805
Alberta	815	3515	1710	7420	33475	46935
Saskatchewan	-	-	-	-	7595	7595
Ontario	-	-	-	-	180	180
New Brunswick	-	-	75	-	-	75
Nova Scotia	-	-	1405	-	-	1405
Yukon Territory and District of Mackenzie	90	-	150	350	2290	2880
Canada	2515	12785	10530	8415	44630	78875

Source: Coal Resources of Canada, Paper 89-4, Geological Survey of Canada, 1989
Note: [a] Thermal coals generally include the lignite - subbituminous, subbituminous-high volatile bituminous and low volatile bituminous - anthracite classes. Metallurgical coals generally include the medium - low volatile bituminous and high - medium volatile bituminous classes.

The portions of the measured and indicated resources of immediate interest that are the most suitable and likely for commercial development are called reserves. Reserves are deposits that have been adequately delineated through exploration and sampling and which can be considered economic for mining using current technology.

The most recent available national assessment of reserves is as of 31 December 1985[1] (Table 9-2). The overall picture of a large inventory of reserves relative to production levels provided by the 1985 data has not changed over the subsequent period. Remaining recoverable reserves are some 90 times Canada's 1989 production of 71 megatonnes. Of these reserves, 71 percent consists of thermal coal. Reserves of lignite are found mainly in Saskatchewan, whereas all subbituminous reserves are located in Alberta. The majority of metallurgical coal reserves are in British Columbia.

9.2 Prices and Transportation Costs

Canadian coal competes in international energy markets with other fuels; for example, with heavy fuel oil and natural gas in the electricity generation market. It also competes with coal from other producing countries. Historically the price of coal has been below that of oil but generally followed crude oil price trends. However, in recent years the coal price has been driven down relative to the crude oil price due to excess availability of coal supply.

1 In order to obtain a current estimate one would have to take into account production and any evaluations of mining properties which have been undertaken since 1985. More current estimates are available for some provinces and for some coal deposits; however, we have chosen to reference an older but complete and consistent set of data.

Table 9-2

Remaining Recoverable Reserves of Coal by Province and Class at 31 December 1985

Province	Class	Megatonnes	Petajoules
British Columbia	Lignitic	566	7600
	Bituminous		
	Thermal	433	10836
	Metallurgical	1563	39114
Alberta[a]	Subbituminous	871	15800
	Bituminous		
	Thermal	800	17115
	Metallurgical	240	5135
Saskatchewan	Lignitic	1670	23000
New Brunswick	Bituminous		
	Thermal	21	500
Nova Scotia	Bituminous		
	Thermal	300	7663
	Metallurgical	115	2937
Canada	Lignitic	2236	30600
	Subbituminous	871	15800
	Bituminous		
	Thermal	1553	36114
	Metallurgical	1918	47186
	Total	6578	129700
Canada	Thermal[b]	4660	82514
	Metallurgical	1918	47186

Source: Coal Mining in Canada: 1986, Report 87-3E, CANMET, September 1987.

Notes: [a] The ERCB estimates coal reserves within mine permit boundaries to be 2586 megatonnes as of 31 December 1989. (ERCB ST90-31)

[b] Thermal includes all lignitic, subbituminous and thermal bituminous reserves.

A worldwide oversupply of coal occurred in the 1980s, as a result of the construction of several new mines dedicated to export markets including some by new low cost competitors, such as China and Colombia. This led to decreasing coal prices for Canadian exporters throughout most of the 1980s. For example, the nominal price in U.S. dollars for metallurgical coal exports to Japan by one producer dropped by 17 percent between 1980 and 1987 (Table 9-3). In Canadian dollars, and taking inflation into account, the real price decrease was approximately 35 percent.

The value of coal varies from one deposit to another depending on properties such as heating value, moisture content, mineral (ash) content and sulphur content. Further, prices for coal production from particular mines are based on specific contractual arrangements. Notwithstanding these factors, the trend shown in Table 9-3 is thought to be generally representative of the prices received by Canadian exporters over this period. The exceptions to this trend are exports originating from the Quintette and Bullmoose mines in British Columbia which were developed based on long-term contracts with Japanese purchasers and have received above world prices.[1]

Nominal prices for coal firmed up by the end of the 80s as a result of a tightening of the supply situation caused by increased demand for coal by the steel industry and by electric utilities. However, for contracts negotiated in U.S. dollars,

1 A recent arbitration decision reduced the price of coal from the Quintette mine to $C 84.40 per tonne as of July 1, 1990.

Table 9-3
Export Contract Base Price of Metallurgical Coal Exports to Japan

Year	Luscar - Medium Volatile[a] (dollars per tonne)	
	$U.S.	$C 1990[b]
1970	11.86	44.31
1975	46.85	114.28
1980	52.79	99.35
1985	50.43	82.84
1986	49.00	79.99
1987	44.00	65.67
1988	46.90	62.42
1989	50.40	61.50

Source: Coal Information 1989, International Energy Agency,1989.
Notes: [a] FOBT.
[b] Calculated using the Canadian GDP deflator and Canada/U.S. exchange rates.

price increases for exports in 1988 and 1989 were essentially negated in real terms by inflation and appreciation of the Canadian dollar relative to the U.S. dollar. We expect that the coal industry will remain highly competitive and that prices on world markets will relate to the long-term trend in production costs.

In certain countries, for example Germany, government support is required to maintain the national coal industry because domestic production costs are above the marginal supply cost of coal on international markets. Such support exacerbates the international excess supply situation and therefore tends to depress world coal prices. There does appear to be movement in some countries to reduce the production and use of uncompetitive domestic coal.

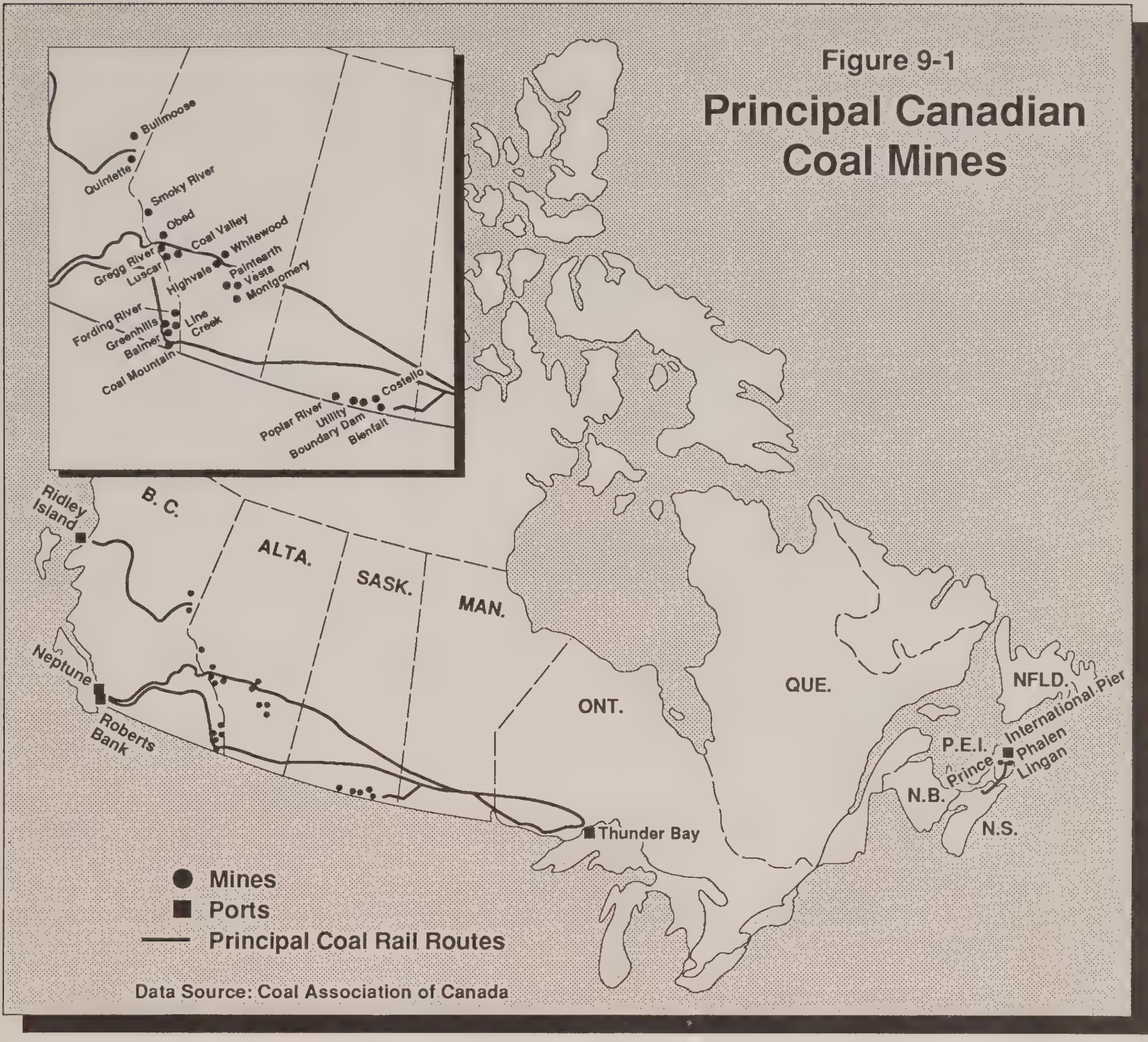
With respect to Canadian markets, we assume that the price of coal for electricity generation and at the industrial burner tip will remain constant in real terms. This implies that the cost of any incremental capacity required to meet domestic demand either at existing mines or in the form of new mine development will not increase from current levels.

Most Canadian mines are surface mines, which generally have very much lower production costs than do underground mines. Costs for Canadian coals at the mine mouth are more than competitive with mine mouth costs at other operations throughout the world. However, the delivered cost of coal consists of both production and transportation costs.

The cost of transporting coal to markets varies widely, depending on the geographic location of the mines, the market being served and the mode of transport. With the exception of coal used for mine site electricity generation, access to both domestic and export markets for western Canadian coal involves long rail hauls, the cost of which accounts for a large part of the delivered price. Western coals exported through terminals in British Columbia are hauled about 1100 kilometres; coals moving east to Great Lakes shipping terminals at Thunder Bay cover about 2200 kilometres (Figure 9-1). Rail charges average over $C 20 per tonne for coals moving to west coast ports and over $C 35 per tonne for shipment east to Thunder Bay. For metallurgical coals exported from the west coast, this represents about one third of the value of the coals at the shipping terminal; it is a higher percentage for thermal coals. These inland transportation costs are higher than those incurred by Colombia, South Africa, Australia or China where the distance from the mines to tidewater is much less. They therefore place Canadian exports at a competitive disadvantage in world markets. This makes it particularly important that Canadian production costs remain competitive with those of other producers.

A number of research projects are underway aimed at improving the ability of Canadian coal to compete in export and domestic energy markets. These include investigating:

- fluidized-bed boiler technology which achieves low levels of acid gas emissions, when compared to conventional pulverized-coal boilers;
- integrated gasification combined cycle technology which is intended to increase the efficiency of electricity generation from coal, and reduce SO_2 and NO_x emissions;
- underground mining techniques which would improve resource recovery and lower production costs associated



with the recovery of coal from thick coal seams;

- upgrading of coals to remove noncombustible matter and excess moisture prior to shipment, thereby reducing transportation costs;

- the feasibility of pipelining coal-oil mixtures, again with the objective of reducing transportation costs.

9.3 Domestic Demand

For the first half of this century, coal was the major source of energy in Canada, accounting for one half of primary energy demand by 1950. During the 1950s and 1960s oil and natural gas displaced coal used for space heating and in general industry, and the railways converted from coal to diesel fuel. In the 1960s, increased use of coal in Ontario by the steel industry and by electric utilities reversed the decline in demand. Expansion in coal demand since 1970 has been primarily for electricity generation in Alberta, Saskatchewan and Nova Scotia. Currently the main uses of coal in Canada are for the generation of electricity (thermal coal) and for the fabrication of iron and steel (metallurgical coal) (Table 9-4). Research is continuing on the conversion of coal to other fuels, and projects aimed at developing new markets for coal are underway.

Table 9-4
Domestic Coal Demand
(Megatonnes)

	1989[a]	1995[b]	2000[b]	2010[b]
Thermal				
Electricity	45.9	43.1	49.3	57.0
Oil Industry[c]	0.0	0.0	0.0	9.0
Other	2.0	2.2	2.3	2.6
Total	48.0	45.3	51.6	68.6
Metallurgical	5.9	7.1	7.5	8.3
Total	53.9	52.4	59.1	76.9

[a] Source: Statistical Review of Coal in Canada: 1989, Energy, Mines and Resources, 1990.
[b] Source: Appendix Table A9-4.
[c] Coal demand for the generation of steam used in the recovery of bitumen.

Thermal Coal

Alberta, Saskatchewan and Nova Scotia are expected to continue to favour coal for electric power generation, with flue gas desulphurization added as required. As discussed in Chapter 5, Ontario Hydro will require less coal in the near future, when new nuclear capacity under construction at Darlington is put into commercial operation. We have assumed that Ontario Hydro will not build any new coal-fired power plants during the projection period. Ontario legislation has imposed a more stringent sulphur dioxide emissions ceiling for 1994 and beyond. We have assumed that these emission standards will be met by installing scrubbers in some existing coal burning plants. Meeting more stringent emission standards will likely mean that generation cost per kilowatt hour will be higher than that implied by today's relatively low prices for medium sulphur coal. It may also reduce the capacity of Ontario's coal-fired generating stations because less electricity will be produced per tonne of coal consumed. In New Brunswick, we assume one coal-fired unit will be constructed.

Fluidized-bed combustion systems and integrated gasification combined cycle power plants are new technologies which have the potential to be more effective in terms of both environmental control and power costs than existing plant technology. A 20 MW circulating fluidized bed demonstration boiler was constructed at New Brunswick Electric Power Commission's Chatham generating station in 1986 and this technology may be considered for future generating stations in New Brunswick. In Nova Scotia, the latest in circulating fluidized bed technology is being installed in a new coal-fired generating station to be built at Point Aconi to restrict SO_2 and NO_x emissions.

In total, we expect that coal use in Canada for electricity generation will decrease from 46 megatonnes in 1989 to 38 megatonnes in 1991 as new nuclear capacity is commissioned in Ontario. After 1991 coal use for electricity generation generally increases over the remainder of the projection period, to over 57 megatonnes by 2010.

The cement industry is currently the largest user of thermal coals in the industrial sector, followed by the smelting and refining industry. Use of coal in the industrial sector is projected to increase from 2 megatonnes in 1989 to 2.6 megatonnes in 2010. In Alberta, the use of coal, rather than natural gas, to generate steam for in situ recovery of bitumen could provide a new market for western coal. Current industry estimates suggest that, at a wellhead price for natural gas of $C 2.50 per gigajoule, coal is competitive with natural gas in some projects. Based on this estimate, our price projection for natural gas which exceeds $C 2.50 per gigajoule in 1999, and on our projections of bitumen production contained in Chapter 7, we project demand for subbituminous coal for steam raising to grow from 0.6 megatonnes in 2001 to 9 megatonnes in 2010.

In total, thermal coal demand in Canada grows from 41.5 megatonnes in 1990 to 68.6 megatonnes in 2010.

Metallurgical Coal

Metallurgical coal demand in Canada is determined by the steel industry's demand for coke, which is located primarily in Ontario. In 1989, the steel industry in Ontario consumed 5.9 megatonnes of bituminous coal, all of which was imported from the U.S. We expect that demand for metallurgical coal in Ontario will continue to be met by imports.

Demand for metallurgical coal grows at an average ratio of just

under two percent per year (Chapter 4), leading to a requirement for 8.3 megatonnes in 2010. This growth in demand is lower than the projected growth in the output of the steel industry because of assumed efficiency improvements in the use of coal to produce finished steel.

Coal Conversion

Co-processing of coal and heavy oil is among the new technologies with potential longer-term impact on domestic demand. This technology may provide an economically viable means of producing liquid fuels from coal.

Ohio Clean Fuels Inc. is proposing a 1900 cubic metre per day upgrader project in Ohio, which would co-process 600 tonnes per day of Ohio coal and 1400 cubic metres per day of heavy crude oil into naphtha and middle distillates. Nova Scotia Synfuels has been proposing a similar project for Cape Breton using Nova Scotia coal and offshore heavy oil. CANMET, the Alberta Research Council and Canadian Energy Developments Inc. are continuing to develop their own co-processing technologies.

In order to be economic, co-processing requires price differentials between the coal and heavy oil feedstocks on the one hand, and the light crude oil products on the other, sufficient to cover upgrading costs. Domestic coal prices, which are below those of heavy oil, are projected to remain constant in real terms. Our projections of heavy oil prices relative to light crude oil are discussed in Section 7.3.6.1. Proponents of co-processing suggest that a reference crude oil price of about $US 25.00 per barrel and light-heavy price differentials of $US 7.00 or greater, depending on the technology, are required to make these projects economic. This is an emerging technology and we have not included in our projections any demand for coal for use in coal-oil co-processing.

9.4 Exports

Canadian coal exports depend on the level of world coal trade and our ability to compete in international markets. Since the early 1970s, world coal trade has increased at about 5.2 percent per year, reaching 373 megatonnes in 1988. Exports from Canada increased at an average rate of almost 12 percent per year over the same period, making Canada the sixth largest coal exporting country in terms of volume. Canada captured 8.4 percent of the export market in 1988. Asia is the destination of 80 percent of exports from Canada.

The Canadian coal exporting industry was developed in Alberta and British Columbia during the 1960s and early 1970s to serve Japanese metallurgical coal markets. Large export contracts with Japanese steelmakers led to the opening of new mines and construction of a bulk shipping terminal at Roberts Bank near Vancouver in 1970.

By 1983 Canadian coal exports reached 17 megatonnes, consisting of 15 megatonnes of metallurgical coal and 2 megatonnes of thermal coal. In 1984, exports jumped by 50 percent as a result of export contracts for coal from new mines in Alberta and northeastern British Columbia. From 1984 to 1987, coal exports were in the neighborhood of 26 megatonnes, more than 80 percent of which was metallurgical coal.

In 1988 and 1989 exports increased to 32 and 33 megatonnes, respectively, mainly to meet demand for metallurgical coals resulting from record production of crude steel.

West coast exports pass through ports at Roberts Bank, Prince Rupert and Vancouver. The combined capacity of these ports is over 40 millions tonnes per year. Exports from the east coast move through a coal terminal at Sydney,

Table 9-5

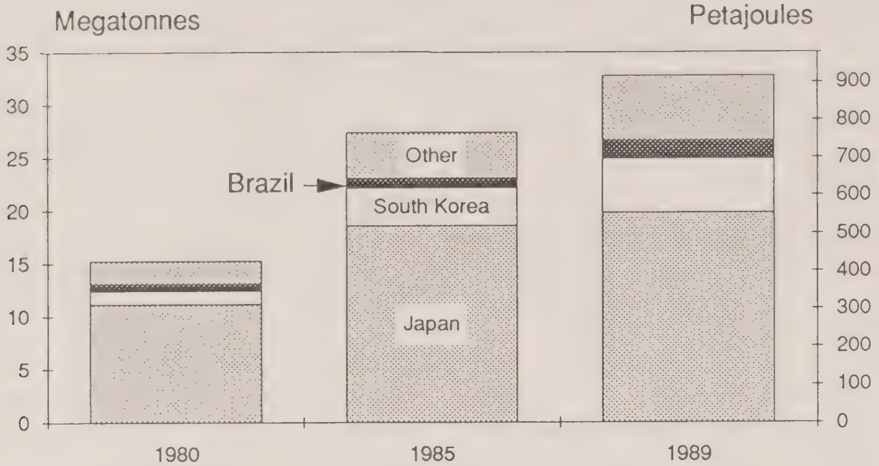
Coal Exports in 1989

	Megatonnes	Petajoules	Percent by Volume
British Columbia	24.1	735.2	73
Alberta	7.4	226.4	23
Saskatchewan	<.1	0.2	<1
Nova Scotia	1.3	36.0	4
Canada	32.8	997.8	100

Source: Statistics Canada, cat. no. 57-003.

Figure 9-2

Coal Exports by Destination



Nova Scotia, which has a capacity of about one million tonnes per year. Table 9-5 provides a summary of exports by province.

Internationally, in 1988 about 14 percent of the metallurgical coal exports and 2 percent of the thermal coal exports originated from Canada.

Japan accounted for 60 percent of total Canadian exports, and South Korea 16 percent, in 1989 (Figure 9-2). Smaller volumes went to Brazil, the U.S., Europe, and other Latin American and Asian countries (Table A9-2).

Metallurgical Coal

Canada has abundant resources of metallurgical coal. Domestic demand is in Ontario and is primarily served by imports from the U.S. Western Canadian metallurigical coal producers are therefore highly dependent on export markets.

Almost 90 percent of Canada's metallurgical coal exports in 1989 was shipped to five countries: Japan, South Korea, Brazil, the U.S. and Taiwan. Exports to Japan have averaged about 18 megatonnes per year over the last two years. Exports to South Korea grew steadily in the 1980s and reached their highest level to date in 1989, up some 15 percent over 1988. Exports to the U.S. have been growing steadily since 1980 but remain a small proportion of total exports. In total, exports of metallurgical coals were up by 3.5 percent in 1989, reaching a record level of 28.6 megatonnes with most mines producing at or near capacity. Canada's main competitors for metallurgical coal markets include Australia, South Africa, the U.S.S.R. and the U.S.

World crude steel production, which drives the demand for metallurgical coals, increased steadily in the years prior to 1973, but has flattened somewhat since then. However, in 1988, there was a six percent increase in production.

In the near term, crude steel production in Japan, Canada's major export market, could decrease because of increased competition on world markets from other steel producing countries and from reductions in domestic demand. Furthermore, Japan is promoting a rationalization of its steel industry which would involve shutting down several older blast furnaces which use more coal per unit of steel output. It is also trying to reduce raw material costs by using less expensive lower quality coals and by displacing expensive domestic coal production with imports.

In addition to the demand for steel, metallurgical coal demand will be influenced by new steel-making technologies. The use of electric arc furnaces to produce steel is increasing. This technology uses scrap iron as feedstock and eliminates the requirement for metallurgical coal. The use of pulverized coal injection technology is also increasing. This technology involves the injection of pulverized coal into blast furnaces without undergoing the coking process. Every tonne of pulverized coal injected replaces one and one-half tonnes of coking coal. Not only does this reduce the demand for coking coals, but it allows the use of soft coking coals, of which Canada is not a major supplier. From 1980 to 1988 soft coking coal use in Japan increased from 3 to 20 percent of total coking coal consumption.

Although total consumption of metallurgical coals may flatten or even decrease in the near term, it is likely that seaborne trade will increase, as relatively expensive production from mines in Western Europe is replaced with lower cost imports, and as steel production in coal importing countries, such as South Korea and Brazil, continues to grow.

Our projections show metallurgical coal exports remaining at current levels throughout the projection

period (Figure 9-3). This assumes that our high quality coking coals will be able to maintain markets, but that we will not share in the increased demand for soft coking coals.

Thermal Coal

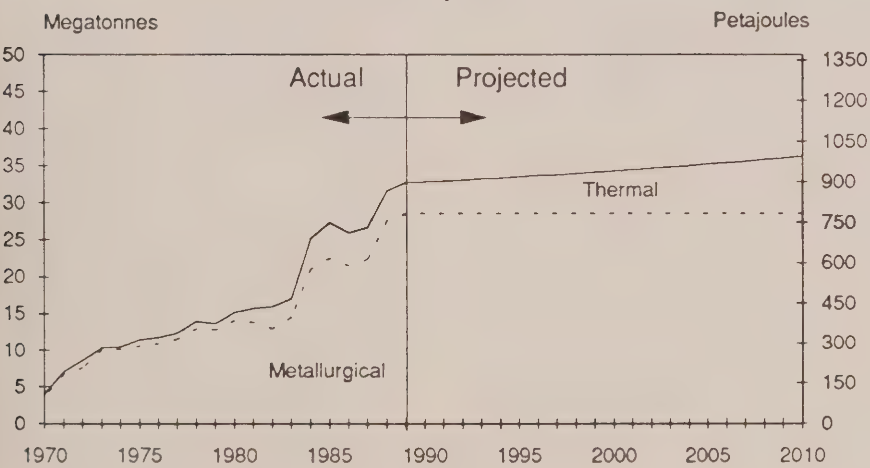
Canada is a relatively small exporter of thermal coal. Since 1984, exports have ranged between 4 and 5 megatonnes per year, with the 1989 level being 4.2 megatonnes. Japan and South Korea were the destination of three-quarters of Canada's thermal coal exports in 1989.

Coal has had a price advantage in the world electricity generation market since the first oil price shock in 1973. Since that time, the world electricity generation market has grown at an average three percent per year. This, combined with the desire of several countries to reduce dependence on imported oil, has resulted in the expansion of coal use at the expense of oil. World thermal coal trade has increased about 5.5 percent per year since 1980, reaching 178 megatonnes in 1988. Future use of coal for electricity generation will depend on growth trends in electricity demand and on fuel choice which may take into account environmental as well as economic considerations.

The outlook for growth of world trade in thermal coals is much more optimistic than for metallurgical coals because of the anticipated growth in requirements for electricity generation, particularly in Asia.

The U.S. Energy Information Administration (EIA)[1] projects that world trade in thermal coals will grow from 179 megatonnes in 1988, to 347 megatonnes in the year 2000, and to 501 megatonnes by 2010. In Western Europe, West Germany and the United Kingdom are projected to become major coal importers, while in Asia the major growth in import demand is likely to occur in Japan, Taiwan and South Korea. Canada, with the majority of its coal mines located in the west, is better positioned to compete in the Asian markets than in Europe.

Figure 9-3
Coal Exports



Source: Appendix Tables A9-3 and A9-4.

In Asia, Canadian producers face competition from Australia and China, which has emerged as a major exporter in the 1980s, as well as South Africa and the U.S. According to the EIA report, steam coal imports into Asian markets could increase from 70 megatonnes in 1988 to 178 megatonnes by 2010, a growth rate of over four percent per year. Potential for increased Canadian exports to the U.S. to serve west coast industrial markets may also exist. In order for Canadian exporters to achieve market growth, Canada will have to capture a portion of new markets in competition with relatively low cost suppliers. This may require importers to, in part, be influenced by a desire to maintain a diversity of supply sources. Based on our consultations with industry and the outlook for growth in thermal coal export markets, we project Canadian exports to increase annually by three percent, less than the expected growth rate in Asian markets. This results in exports growing from 4.2 megatonnes in 1989 to 7.7 megatonnes by 2010. Based on the EIA projections of world coal trade and our projections of exports, our market share of world thermal coal trade would consequently decrease from 2.3 percent in 1988 to 1.5 percent by the end of the projection period.

9.5 Imports

In 1989, imports met almost 27 percent of domestic coal demand. Imports, all of which came from the U.S., were 14.7 megatonnes, of which 94 percent was to Ontario (Table 9-6). Seventy-five percent of Ontario Hydro's

1 *Annual Prospects for World Coal Trade: 1990*, Energy Information Administration, U.S. Department of Energy, June 1990.

Table 9-6

Coal Imports in 1989

	Megatonnes	Petajoules	Percent by Volume
Ontario	13.7	397.1	94
Quebec	0.7	19.3	5
New Brunswick	0.1	4.2	1
Canada	14.5	420.7	100

Source: Statistics Canada, cat. no. 57-003.

Table 9-7

Coal Production by Province and Class in 1989

Province	Class	Megatonnes	Percentage of Total Production	Petajoules	Percentage of Total Production
British Columbia	Bituminous				
	Thermal	3.1	4	96	6
	Metallurgical	21.7	31	662	39
Alberta	Bituminous				
	Thermal	4.2	6	129	8
	Metallurgical	5.7	8	172	10
	Subbituminous	20.9	30	383	22
Saskatchewan	Lignite	10.8	15	162	9
New Brunswick	Bituminous				
	Thermal	0.5	1	14	1
Nova Scotia	Bituminous				
	Thermal	2.8	4	79	5
	Metallurgical	0.8	1	22	1
Canada	Bituminous				
	Thermal	10.7	15	317	18
	Metallurgical	28.1	40	856	50
	Subbituminous	20.9	30	383	22
	Lignite	10.8	15	162	9
	Total	70.5	100	1718	100
Canada	Thermal	42.4	60	862	50
	Metallurgical	28.1	40	856	50

Source: Statistical Review of Coal in Canada:1989, Energy Mines and Resources, Canada, 1990 and Statistics Canada cat. no.57-003.

requirement for bituminous coals for electricity generation was met by imports, as well as essentially all of the industrial demand in Ontario for thermal and metallurgical coals. The remainder of the supply came from Western Canada. In Quebec, 84 percent of the industrial demand for thermal coals was satisfied by imports with the remainder coming from Nova Scotia. In our projections we are assuming that Quebec will continue to be supplied mainly by U.S. coals and that in Ontario, because of high transportation costs, western Canadian bituminous coals will maintain but not increase their share of the market. In sum, competition between domestic and U.S. coals is projected to result in the import shares of thermal and metallurgical coal consumption in Ontario and Quebec remaining constant.

By 2010, imports of thermal coal, related mainly to requirements for electricity generation in Ontario, are projected to be 11.4 megatonnes. We project that imports of metallurgical coal (which amounted to 5.8 megatonnes in 1989) will grow over the study period to 8.3 megatonnes in response to growth in demand from Ontario's steel industry.

9.6 Production

In 1989, 17 major companies operated twenty seven principal mines in Canada. These mines had the capacity to produce 47 megatonnes of thermal coals and 33 megatonnes of metallurgical coals. Actual production of thermal coals totalled over 42 megatonnes, or 90 percent of capacity; production of metallurgical coals totalled over 28 megatonnes, or 85 percent of capacity. Except for Cape Breton Island mines, for one mine

on Vancouver Island and for one in Alberta, all Canadian production is from surface mines.

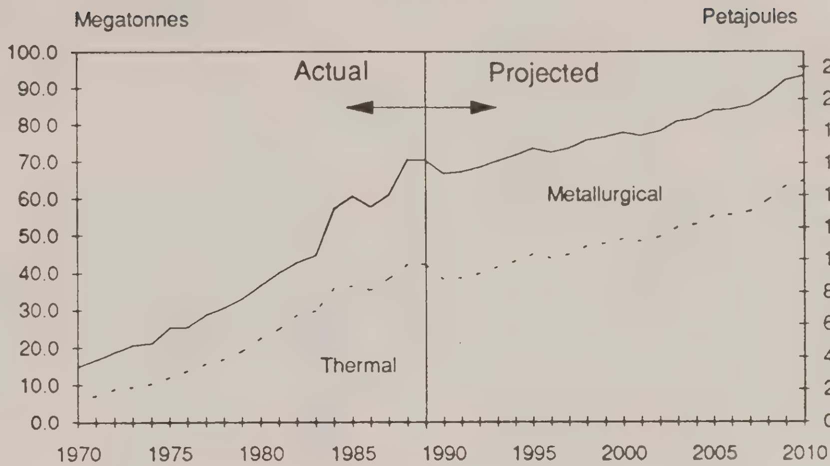
Coal production has more than doubled in ten years, from 33 megatonnes in 1979 to 71 megatonnes in 1989. Growth in metallurgical coal production, from 14 to over 28 megatonnes, resulted from increases in exports; growth in thermal coal production, from 19 to over 42 megatonnes, resulted mainly from growth in domestic coal-fired electricity generation (Appendix Table A9-3).

Coal production in 1989 is summarized by province and class in Table 9-7. Bituminous coals represented 55 percent of the total production in 1989 on a volume basis; subbituminous and lignitic coals accounted for 30 and 15 percent, respectively. All subbituminous and lignitic coals, plus over 25 percent of the bituminous coals, were used for thermal purposes; this amounted to 42 megatonnes or 60 percent of production. Canada does not currently produce any anthracite.

In 1989, Alberta produced 30.8 megatonnes of coal or 44 percent of total Canadian production. Coal production in British Columbia totalled 24.8 megatonnes and in Saskatchewan 10.8 megatonnes. Production in the Atlantic provinces was 4.1 megatonnes, representing only 6 percent of total Canadian output.

Our projection of future Canadian production levels is based on the estimates of domestic demand and exports previously discussed, net of imports. We expect coal production to increase modestly, reaching 93.5 megatonnes per year in 2010 (Figure 9-4 and Appendix Table A9-4).

Figure 9-4
Coal Production



Source: Appendix Tables A9-3 and A9-4.

9.7 Concluding Comments

There are several uncertainties associated with the future supply of and demand for coal in Canada. These include the extent to which:

- environmental concerns will impact on demand;
- clean coal technologies will mitigate environmental concerns;
- coal will be able to displace natural gas used in the production of steam required for bitumen production;
- Canada will be able to preserve its position in world metallurgical coal markets and participate in expanding markets for thermal coal;
- Ontario Hydro will use coal for electricity generation; and
- the Ontario market will be served by Western Canadian coal.

Our projections in the Control Case show considerable growth in domestic demand for coal over the projection period. In Ontario and Quebec markets, domestic supply continues to face stiff competition from U.S. coals, and Canadian producers are not expected to increase their market shares. Growth in electricity generation markets in the West and in the Atlantic region are projected to result in increased demand for Canadian coals. Overall, domestic demand in the Control Case grows from 47 to 77 megatonnes.

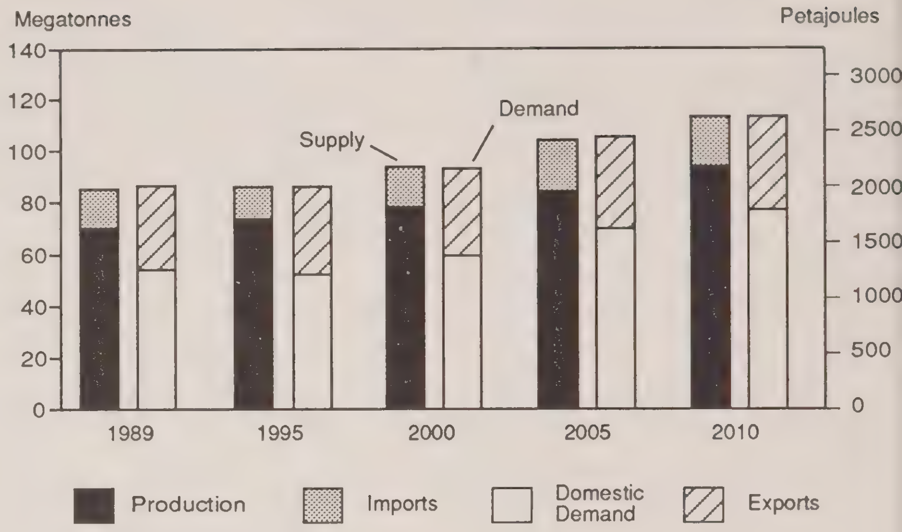
With regard to world coal trade we see continued growth, particularly for thermal coals. Canada is at a competitive disadvantage in some markets, mainly because of high transportation costs incurred in moving coals long distances by rail to tidewater and the emergence of new low cost suppliers on the world scene. We have assumed that we will be able to expand our exports of thermal coal, but that overall we will lose market share. Expansion of thermal coal exports

may depend on the extent to which buyers wish to maintain diverse supply sources. With regard to metallurgical coal exports we have assumed that we will be able to maintain our existing level of exports.

In summary, we project growth in Canadian coal production to satisfy increases in both domestic and export demand. However, this growth is dependent on our ability to continue to be cost competitive with other sources of coal, on the desire of buyers in export markets to maintain a diversity of suppliers, and on the continued acceptability of coal from an environment standpoint (Figure 9-5).

Figure 9-5

Coal Supply and Demand in Canada Control Case



Source: Appendix Table A9-4.

Chapter 10

Sources and Uses of Energy

This chapter summarizes our projections of Canadian energy demand, supply and international trade, and compares Canadian energy flows to those observed in other countries.

Figure 10-1 shows energy flows in Canada and illustrates the relationship between the sources and uses of energy in 1989 and in 2010.

In moving from primary sources of energy to end use demand, we first identify all sources of primary energy, including domestic primary energy production and imports. Subtracting exports from these energy sources leaves domestic demand for primary energy.

To arrive at end use demand for primary energy, we subtract fuel use and losses associated with the production and distribution of energy. These include:

- fuels to produce oil and natural gas and move them from the field to final markets;
- fuel and losses in crude oil refining and in the reprocessing of natural gas to extract liquids;
- utilities' own use and losses in the transmission and distribution of electricity;
- conversion losses in electricity generation when coal, natural gas, oil and uranium are used in generating plants; for every unit of electricity produced, approximately three units of fuel input are required. We use a conversion factor of 10.5 petajoules per terawatt hour for electricity generated from fossil fuels and 12.1 petajoules per terawatt hour for electricity generated from uranium. The conversion factor for electricity generated from natural gas, from highly efficient combined cycle units or through industrial cogeneration is less than 10.5, depending on the technology. (We convert hydroelectricity at 3.6 petajoules per terawatt hour. See Chapter 5.)

10.1 Canadian Energy Supply, Demand and Trade

Production of primary energy grows at 1.3 percent per year from 1989 to 2010 in the Control Case. Oil's share of total primary energy production, which was 31 percent in 1989, declines to 27 percent in 2010 (Figure 10-2). Natural gas, which represented 33 percent of Canada's energy production in 1989, accounts for 34 percent of primary production in the year 2010. Coal's share of primary production is stable at 14 percent throughout the projection. In 1989, hydro and nuclear production together accounted for about 16 percent of total primary production. In 2010, this share is 18 percent (Figure 10-2).

Canada imports only coal and petroleum in volumes large enough to make an appreciable difference between gross and net exports. Coal imports rise from 424 petajoules in 1989 to 569 petajoules by the year 2010, as growth in demand for both bitumen production and electricity generation outpaces production. Petroleum imports also rise from about 1480 petajoules in 1989 to 2421 petajoules in the Control Case in 2010.

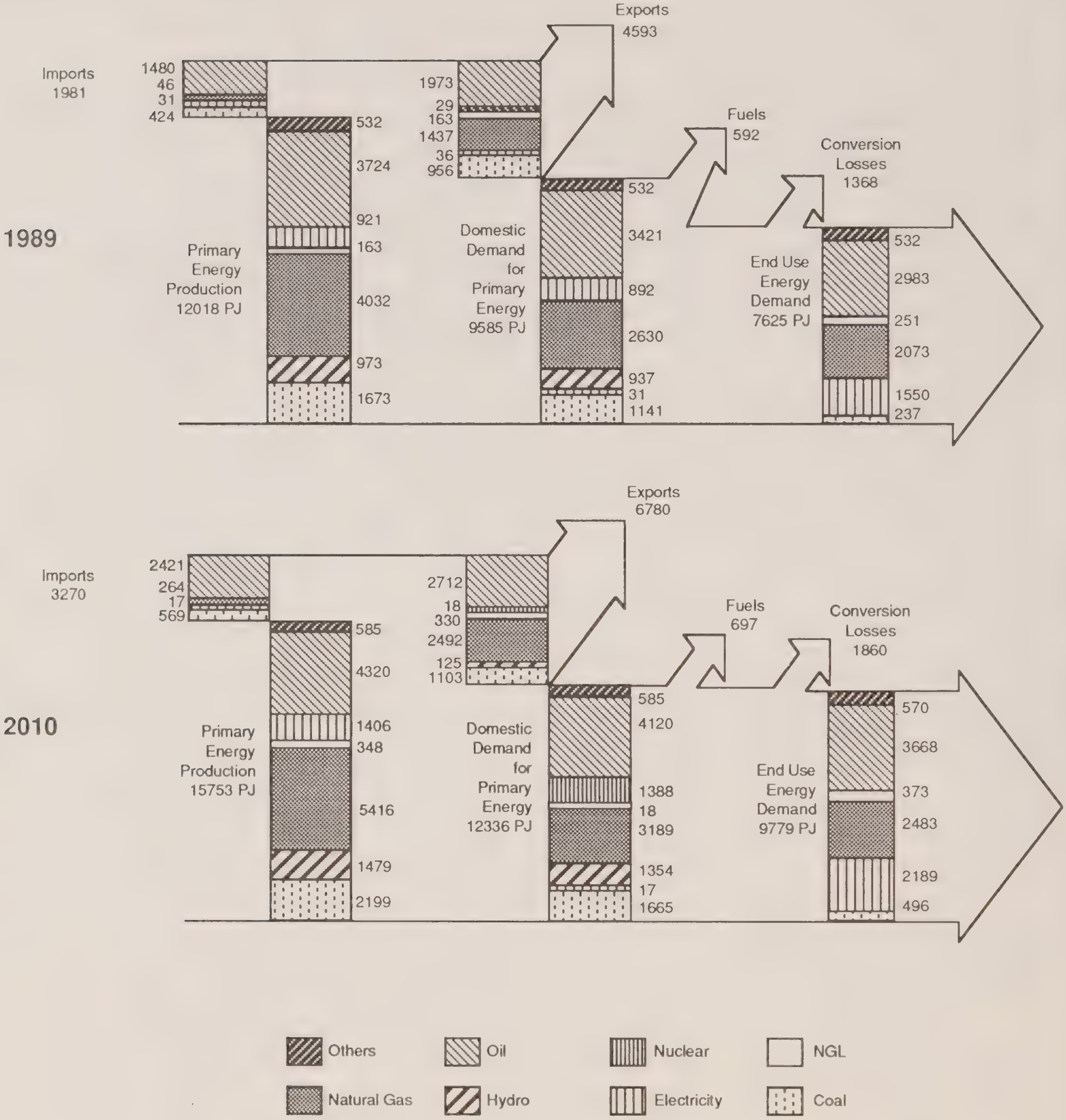
In 1989 Canada imported 1.2 billion cubic metres (46 petajoules) of natural gas from the U.S. to eastern Canada, equivalent to 1.1 percent of total Canadian production. Over the projection period this volume increases to 264 petajoules, or 4.8 percent of total production.

In 1989, 38 percent of Canada's primary energy production was exported: thus exports are an important determinant of Canada's energy output. By 2010, in the Control Case, 43 percent of Canadian primary production is exported. Natural gas exports in 1989 accounted for 12 percent of primary production. By 2010, this share increases to almost 16 percent. The share of primary production represented by oil exports remains fairly constant, at close to 17 percent throughout the projection period, although the mix of exports shifts towards heavy crude. Exports of coal decline slightly as a share of primary production, from almost 8 percent in 1989 to 7 percent in the year 2010. Exports of NGLs account for the remaining 2 percent.

Figure 10-1

Energy Flows

(Petajoules)

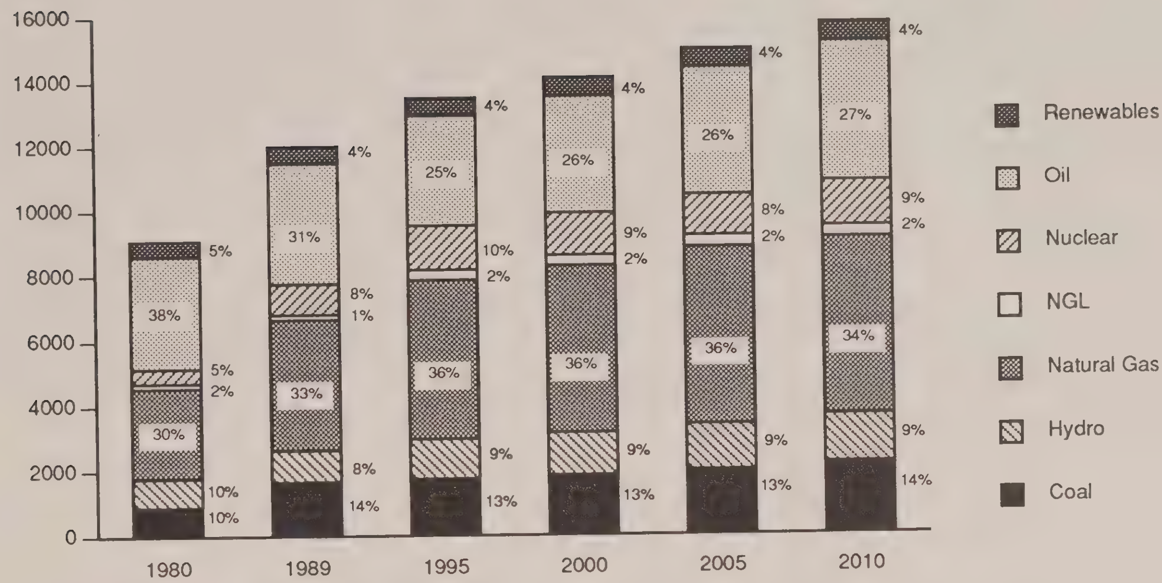


Note: Hydro electricity converted to PJ using 3.6PJ/TW.h. and nuclear electricity converted to PJ using 12.1 PJ/TW.h.

Source: Appendix Table A10-1.

Figure 10-2

Primary Energy Production by Fuel
Canada
(Petajoules)



Source: Appendix Table A10-1.

In 1989, net exports were 2540 petajoules, the result of exports of about 4520 petajoules and imports of 1980 petajoules (Table 10-1). In the year 2010, net exports are 3435 petajoules. As seen in the Table, there are several major shifts in the distribution of net exports over the period. By 2010, net exports of oil are only 290 petajoules, compared to 475 petajoules in 1989, as growing demand for product and declining domestic production of light crude lead to growth in imports (mainly product and light crude) at a much faster rate than exports (mainly heavy crude). Net exports of natural gas increase from 1380 to 2230 petajoules between 1989 and 2010. Coal net exports increase from their level of 480 petajoules in 1989 to 565 petajoules in 1995, but decline to 435 petajoules in 2010. Net exports of NGLs increase from 180 to 330 petajoules and net electricity exports grow from their extraordinarily low level of 25 petajoules in 1989 to 150 petajoules in 2010.

Figure 10-3 shows primary energy demand for domestic use for our Control Case, along with historical data. Over the projection period, oil's share of demand declines from 36 percent in 1989 to

Table 10-1

Net Energy Exports (Imports)
(Petajoules)

	1975	1989	1995	2000	2005	2010
Coal	(145)	480	565	495	400	435
Electricity	10	25	180	150	160	150
Natural Gas	1040	1380	1995	2070	2260	2230
NGL	145	180	310	310	345	330
Crude oil & products	(110)	475	25	110	210	290
Total	**940**	**2540**	**3075**	**3135**	**3375**	**3435**

Note: The numbers on this table have been rounded to the nearest unit of five.

Source: Appendix Table A10-1.

33 percent in 2010. The share of natural gas in primary energy demand falls slightly from 27 percent in 1989 to 26 percent, while primary demand met by hydro and nuclear generation rises from 19 percent in 1989 to 22 percent in 2010. Coal's share increases from 12 percent to almost 13.5 percent in 2010. Over the outlook period total domestic demand for primary energy grows at 1.2 percent annually, the same growth rate as end use demand.

10.2 International Perspective

Governments and international organizations have been making comparisons of energy use and energy intensity[1] for many years. These comparisons are frequently used to indicate the relative efficiency of energy use across countries at a given point in time, or the extent to which countries are improving their energy efficiency relative to others over time.

Table 10-2 shows the populations of each OECD country, energy demand, production, net imports, and energy use per capita.[2]

In previous reports we have examined energy use per dollar of GDP, and compared this measure across countries. Such analysis suffers from two drawbacks:

- The first is that each country's GDP must be measured in some common currency. Large

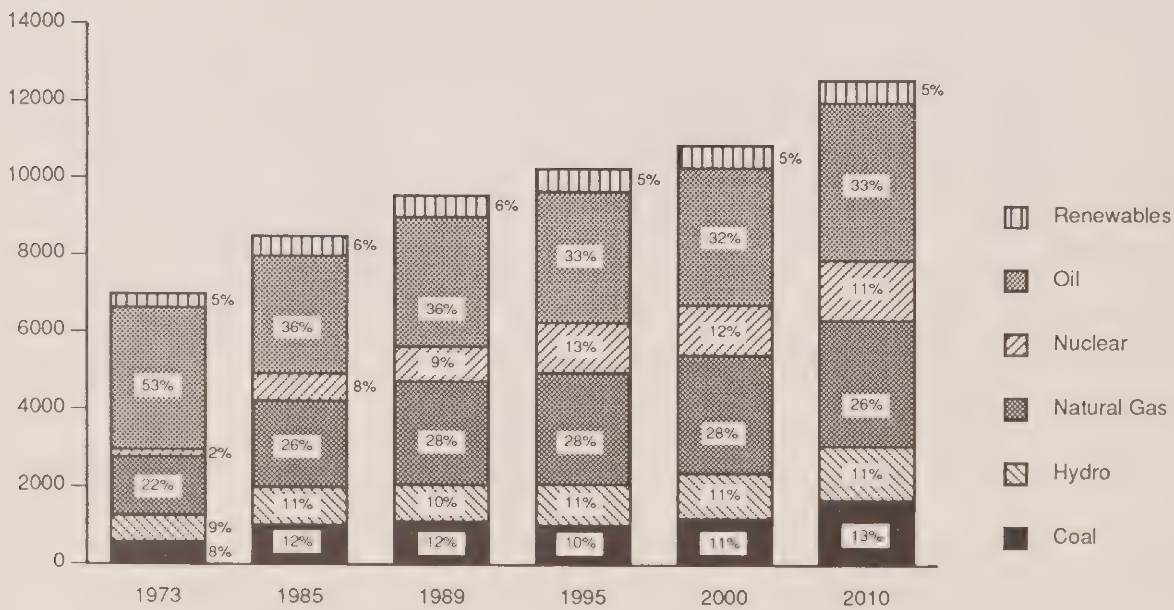
1 Energy use per capita or per unit of goods and services produced.

2 Hydroelectricity has been converted using a factor of 3.6 PJ per TW.h, reflecting the fact that water used to produce electricity does not have an alternate use in the context of energy production. International comparisons are often complicated by the fact that certain agencies still use a conversion factor for hydroelectricity that implies a plant efficiency of 38.5 percent (as though fossil fuel were used to generate the electricity), which results in a conversion rate of about 10 PJ/TWh. When this kind of fossil fuel equivalent measure is used, countries which increase their share of hydroelectricity while reducing their fossil fuel dependence are made to appear more energy intensive or less energy efficient than is in fact the case. To date most data which allows a historical comparison of energy use - per capita or otherwise - is based on this "fossil fuel equivalence" measure.

Figure 10-3

Domestic Demand for Primary Energy by Fuel Canada

(Petajoules)



Source: Appendix Table A10-1.

Table 10-2

COMPARISON of ENERGY USE and PRODUCTION in OECD COUNTRIES in 1988

	Population (Millions)	Primary Energy Demand (PJ)	Energy Production (PJ)	Net Energy Imports (Exports) (PJ)	Primary Energy Demand Per Capita (GJ)
Australia	16.5	3374	5777	-2403	204
Austria	7.6	997	340	657	131
Belgium	9.9	1914	497	1417	194
CANADA	**26.0**	**8683**	**11150**	**-2467**	**335**
Denmark	5.1	795	327	468	155
Finland	5.0	1160	446	714	234
France	55.9	8293	3668	4625	148
Germany	61.4	11358	5329	6029	185
Greece	10.0	841	347	494	84
Iceland	0.3	44	16	28	177
Ireland	3.5	400	122	278	113
Italy	57.4	6085	994	5090	106
Japan	122.6	16136	2396	13740	132
Luxembourg	0.4	136	4	131	357
Netherlands	14.8	2701	2302	399	183
New Zealand	3.3	464	386	77	139
Norway	4.2	750	3832	-3082	178
Portugal	10.3	587	96	491	57
Spain	39.0	3334	1195	2139	85
Sweden	8.4	1946	1137	808	231
Switzerland	6.7	967	380	586	145
Turkey	54.2	1939	1014	925	36
U.K.	57.1	8690	9642	-952	152
U.S.	246.3	79379	66300	13078	322
Total	**825.8**	**160971**	**117698**	**n.a.**	195
Canada - percentage of total	3.1%	5.4%	9.5%	n.a.	n.a.
- rank	9th	5th	2nd	n.a.	2nd

Notes: The numbers on this table have been rounded.
Hydro electricity converted to PJ using 3.6 PJ per TW.h, and nuclear electricity converted to PJ using 10.5 PJ per TW.h.
n.a.: not applicable

Sources: OECD, Energy Balances of OECD Countries 1987/1988; Paris, 1990.

changes in the exchange rates of most countries, relative to the U.S. dollar, have meant that any analysis of data expressed in a common currency can be more influenced by exchange rate changes than by underlying changes in energy intensity. For example, the ranking of country energy use per dollar of GDP can be completely altered just by exchange rate shifts, making such comparisons questionable at best. Energy use per capita avoids this problem, but it is still not an indicator of efficiency.[1]

- The second is that even if output were expressed in the country's own currency, this measure of *intensity* would not indicate how *efficiently* energy was being used. Recalling the distinction between energy intensity and efficiency discussed in Chapter 4, energy intensity can be affected, for example, by structural changes, shutting down energy intensive industries, or by a shift to hydroelectricity from a fossil fuel; these factors would change intensity but they do not indicate whether energy is being used more efficiently.

In terms of energy production, Canada ranked second in the OECD in 1988, behind the United States, with the United Kingdom third. Total Canadian demand was the fifth highest of OECD countries, after the United States, Japan, Germany (West), and the United Kingdom. Canada had the second highest net exports of any OECD country in 1988, at 2467 PJ, behind Norway which exported 3082 PJ (net). Japan was the largest net importer at 13 740 PJ, or 85 percent of its demand. The United States, although importing close to the same volume as Japan - at 13 078 PJ (net) - met only 16 percent of its demand through imports.

On a per capita basis, energy use in Canada ranks second to that in Luxembourg, above that of any other major industrialised country. It is inappropriate, however, to conclude from this observation that Canadians are relatively wasteful energy users. Different industrial structure, low cost resources, climate and distance between population and industrial centres are all factors which lead to higher per capita energy use in Canada than in other countries. Moreover, it is not surprising that Canada has a relatively energy-intensive industrial sector, insofar as much of Canada's industrial strength was built on its abundance of energy resources.

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1 Other aggregate denominators, such as tonnes of product, suffer similar drawbacks to the GDP measure, to the extent that they are aggregates of non-homogeneous items. Although per capita energy use is not an indicator of energy efficiency, being an aggregate of all energy use for all purposes, population data is not prone to random distortion by factors such as exchange rate movements, and is therefore preferable to GDP for inter-country comparisons over time.

Chapter 11

Environmental Implications of Energy Supply and Demand

11.1 Overview of Sources of Gaseous Emissions

Gaseous emissions produced by the energy sector include those from the combustion of fossil fuels as well as fugitive emissions, which are unintended emissions from the various stages of fuel processing, transportation and handling. The gases considered here are:

- carbon dioxide (CO_2);
- nitrogen oxides (nitric oxide (NO) and nitrogen dioxide (NO_2), which are grouped together and abbreviated as NO_x);
- volatile organic compounds (VOC), which in this report include only photochemically reactive hydrocarbons such as the alkanes, alkenes, aromatics aldehydes and ketones (i.e. VOC exclude methane, ethane and the chlorinated organics);
- methane (CH_4); and
- sulphur dioxide (SO_2).

This chapter begins with a brief description of the underlying environmental issues associated with these gases and puts the energy sector contribution into perspective by comparing energy-related emissions to those from other anthropogenic and natural sources. It then provides our estimates of emissions in the Control Case.

Table 11-1 summarizes the environmental issues associated with each type of emission.

Environmental Issues

The main environmental issues discussed below are:

- possible global warming as a result of increased atmospheric concentrations of the so-called greenhouse gases;
- acidic precipitation (popularly known as acid rain); and
- low-level (tropospheric) ozone.

Global warming is an issue that may have consequences worldwide, as the gases implicated are widely dispersed and are increasing on a global scale. *Acidic precipitation* is a problem which is more regional in scale, as the emissions involved are carried downwind and are deposited relatively quickly after being emitted. *Low-level ozone*, which is produced as a result of photochemical reactions involving NO_x and VOC, is a primarily urban problem; however, it is also becoming a concern in certain agricultural and forest areas, particularly those in the vicinity of

Table 11-1
Summary of Emissions and Related Environmental Issues

Gaseous Emissions	Environmental Issue
Carbon dioxide (CO_2)	Potential global warming
Nitrogen oxides (NO_x)	Acid rain Low-level ozone Potential global warming[1]
Volatile organic compounds (VOC)	Low-level ozone Potential global warming[1]
Methane (CH_4)	Potential global warming
Sulphur dioxide (SO_2)	Acid rain

1 NO_x and VOC may contribute indirectly to global warming as they react in the atmosphere to form low-level ozone, which is a "greenhouse gas".

large urban centres. This issue of low-level ozone is not directly related to the concerns associated with the depletion of the Earth's naturally occurring upper ozone layer. Certain man-made chemicals, notably chlorofluorocarbons, have been implicated as causing thinning of the upper ozone layer. These substances are not released as a result of the production or consumption of energy, however, so this issue is not considered in this report.

Global Warming

The Earth's atmosphere and surface are heated by incoming solar radiation. A thermal equilibrium is reached when the energy lost by the earth through radiation to space equals the incoming energy. Water vapour and certain naturally occurring gases retain some of the outgoing terrestrial radiation, forcing the terrestrial system to reach a higher temperature than would be the case if those gases were absent. Because water vapour and other radiatively active gases act similarly to panes of glass in greenhouses, they are termed "greenhouse gases".

As human activities lead to a continuous increase in the atmospheric concentrations of the greenhouse gases, it is reasonable to expect a certain warming of the earth. There is, however, a lack of agreement as to the timing and magnitude of the warming (the earth's surface temperature being determined not simply by a radiative balance), as well as the relative importance of the contribution of various human activities. In this report, we simply recognize that energy-related emissions are in part the cause of increasing concentrations of greenhouse gases in the atmosphere.

Several gases produced as a result of human activities are considered by many scientists to contribute significantly to the increase in concentrations of greenhouse gases: CO_2, CH_4, chlorofluorocarbons (CFC-11 and CFC-12), and nitrous oxide (N_2O).[1] Of these gases, all except chlorofluorocarbons are produced, to a greater or lesser extent, as a result of the production, processing, transportation, or burning of fossil fuels, as discussed later in this chapter.

1 N_2O is produced as a result of the combustion of fossil fuels; however, because data on N_2O emissions from fossil fuel combustion are not available, projections of emissions of this gas are not presented in this report.

TABLE 11-2
Comparison of Greenhouse Gases

	CO_2	N_2O	CFCs[1]	CH_4
Current global emissions (megatonnes/year)	16 000-29 000	16-28	0.77	135-395
Current rate of increase	0.4 %	0.25 %	5 %	1.1 %
Radiative Efficiency Relative to CO_2[2]	1	160	4 700 - 6 200	70
Lifetime (yrs)	40-?	150	75	7-10
Cumulative Warming Effect Relative to CO_2 (over 50 years)[2,3]	1	200	6 000 - 8 000	20

Source: Equivalency of Greenhouse Gases, D. Etkin, Environment Canada, CO_2 Climate Report, No. 90-01, Spring, 1990.

1 Includes CFC-11 and CFC-12.
2 Calculations based on equal masses of each gas.
3 Cumulative climate effect based on CO_2 lifetime of 40 years.

There are two factors which determine the potential of a particular gas to contribute to atmospheric warming; its concentration in the atmosphere and its radiative efficiency (or capability to trap heat). The concentration of a gas in the atmosphere is a function of its emission rate and its residence time, which is the amount of time before the gas leaves the atmosphere due to its destruction through chemical reactions or its uptake by other parts of the earth or oceans. Table 11-2 shows, for example, that the current emissions of CFCs are extremely small compared to CO_2 while their radiative efficiencies and residence times are comparatively large. The result is that the estimated increase in the atmospheric greenhouse capability due to CFCs amounts to about half that of CO_2. It is only because there are huge quantities of CO_2 emissions that it is the prime gas of concern in the climate warming issue. We have not attempted to put all the emissions considered in this report on a single standardized basis.

Acidic Precipitation

Acidic precipitation includes rain, snow, sleet and hail having a higher acidity than that which would occur in a natural atmosphere; acidic precipitation normally has a pH lower than 5.6. It results primarily from man-made emissions of sulphur oxides (mainly SO_2) and of NO_x. The SO_2 and NO_x combine with moisture in the atmosphere to form sulphuric acid (H_2SO_4) and nitric acid (HNO_3), respectively. Acidic precipitation also includes the process whereby particulate matter such as fly ash, sulphates and nitrates, as well as gases such as SO_2 and NO_x, are deposited on or adsorbed onto surfaces. Those particles or gases can be converted to acids when water is present.

Low-Level Ozone

Ozone is produced in the lower atmosphere (troposphere) as a result of photochemical reactions involving NO_x and VOC, and is a major component of urban smog. Because the necessary reactions are dependent on sunlight and temperature, tropospheric ozone concentrations tend to be highest on warm, sunny days. Ozone can impede respiratory function, and elevated concentrations can affect human health. This occurs particularly in urban areas. Also, concentrations of ozone in many rural areas of Canada have been found to be high enough to adversely affect crop productivity. Tropospheric ozone is also considered to be a potential contributor to global warming.

Gaseous Emissions

Gaseous emissions from the Canadian energy sector are compared with non-energy-related emissions in Figure 11-1.[1]

Recent estimates of total annual Canadian emissions from human activities of the various gases dealt with in this report range from 471 000 kilotonnes in the case of CO_2 to just under 2 000 kilotonnes in the case of VOC. It must be emphasized, however, that although the data presented in Figure 11-1 is very recent, as research into these matters continues more accurate estimates will likely be developed.

Energy-related emissions comprise the major portion of total man-made emissions for CO_2, NO_x and VOC, accounting for approximately 92 percent, 95 percent and 60 percent respectively, of total emissions. Energy-related sources of CH_4 are responsible for only about 16 percent of total emissions. The energy sector accounts for about 45 percent of emissions of SO_2. Thus, the energy sector is an important, although by no means the only, source of emissions of environmental concern.

Carbon Dioxide (CO_2)

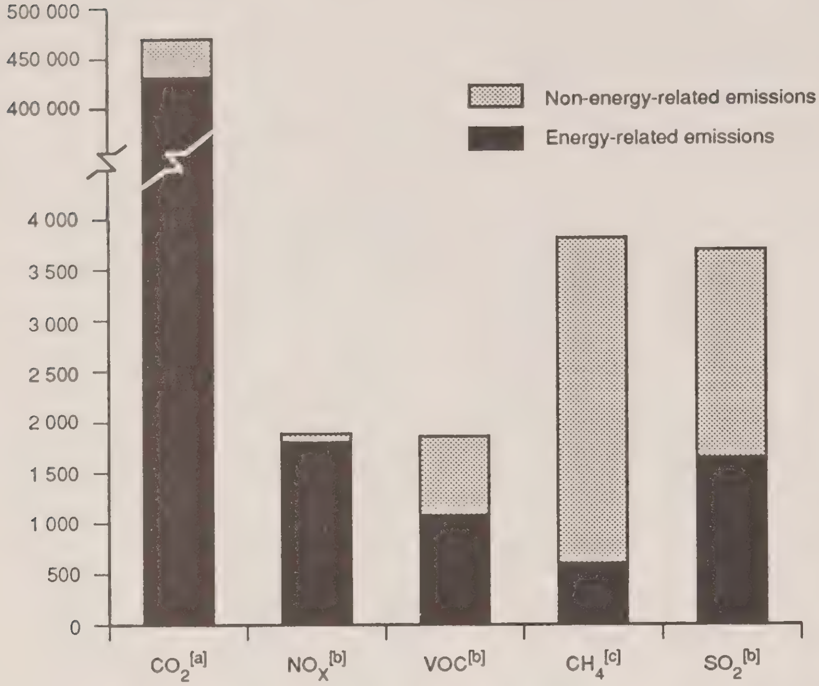
Concentrations of CO_2 in the atmosphere are increasing as a result of human activities. Based on the evidence obtained from sampling air trapped in glaciers, scientists have estimated that prior to the industrial revolution, atmospheric concentrations of CO_2 world-wide were about 280 parts per million by volume (ppmv), compared with 348 ppmv in 1987. Among the relatively well understood sources of CO_2 emissions, those associated with the generation of energy through the combustion of fossil fuels predominate.

There are a number of other important sources, both natural and man-made, of this gas for which estimates are unavailable. For example, the production of CO_2 from human activities such as forest cutting (which, in addition to producing CO_2, also reduces its rate of removal from the atmosphere through photosynthesis by trees) and soil management prac-

1 The emissions estimates quoted represent recent data from Environment Canada. These estimates represent the results of calculations using various models, rather than actual measurements. They are based on various assumptions which may differ from those used in this report, and so may not be entirely consistent with our estimates presented later in this chapter. They are presented here for illustrative purposes to show the relative contribution of various fuels and economic sectors to total emissions of the various gases considered in the report.

Figure 11-1

Canadian emissions from man-made sources of gases considered in this report



[a] Source: *National Inventory of Sources and Emissions of Carbon Dioxide*, A.P. Jaques, Environment Canada, Environmental Protection Series. Report EPS 5/AP/2, May, 1990.

[b] Source: [a] Source: National Inventory of Sources and Emissions of Carbon Dioxide, A.P. Jaques, A. Kostelz and M. Deslauriers, Environment Canada, Environmental Protection Series. Report EPS 5/AP/3, March, 1990.

[c] Source: *Greenhouse Gas Emissions, Estimates for Canada*, A.P. Jaques, Environment Canada, February, 1991.

tices is unknown, yet it is possible that CO_2 emissions from these sources are far from negligible. As additional research is carried out with regard to these emissions, a better understanding of the relative importance of the energy industry will likely be developed.

To put Canada's contribution of CO_2 into perspective, Canada is the world's ninth largest producer of CO_2 emissions, with a 2 percent share of the global total, and the second largest source on a per capita basis.[1]

Man-made emissions of CO_2 in Canada, not including emissions from forest cutting and soil management, total approximately 471 000 kilotonnes, of which about 92 percent, or about 435 000 kilotonnes, is generated by the combustion of various fuels for the production of energy. The incineration of wastes, and cement and ammonia production are relatively less important sources, as is the burning of forest cutting residues.[2] Within the energy sector, the combustion of fossils fuels accounts for about 91 percent of the emissions, with the remainder being produced by the burning of spent pulping liquor and wood fuel.

Emissions of CO_2 from combustion of fossil fuels are a function of the amount of fuel being consumed as well as the per unit emissions rate associated with that fuel.[3]

From a sectoral point of view, stationary combustion sources (industrial boilers, and residential and commercial heating), power plants and the transportation sector are the most significant producers of CO_2, accounting for 38 percent, 22 percent and 33 percent, respectively, of energy-related emissions (Figure 11-3).

Nitrogen Oxides (NO_X)

Total Canadian emissions of NO_x in 1985 were almost 1 900 kilotonnes.[4] Over 95 percent of Canadian emissions of NO_x, approximately 1 800 kilotonnes, are

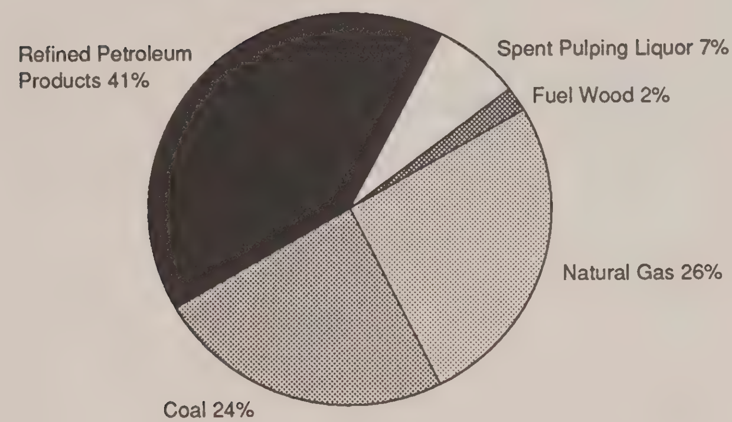
1 *Report on Reducing Greenhouse Gas Emissions*, Federal/Provincial/Territorial Task Force on Energy and the Environment, August, 1989.

2 *National Inventory of Sources and Emissions of Carbon Dioxide*, A. P. Jaques, Environment Canada, Environmental Protection Series, Report EPS 5/AP/2, May, 1990.

3 CO_2 emissions per energy content vary for each fuel type and are a function of its chemical composition. For example, natural gas has an emission rate of about 50 tonnes of CO_2 per terajoule of energy released. Liquid fuels such as gasoline, propane and fuel oil have values ranging from about 60-75 tonnes per terajoule. Solid fuels such as coal and lignite range from about 80 to 110 tonnes per terajoule. Thus, although the per unit emissions rate for natural gas is relatively low compared to, for example, coal, the large volumes of natural gas combusted annually in Canada result in substantial emissions of CO_2.

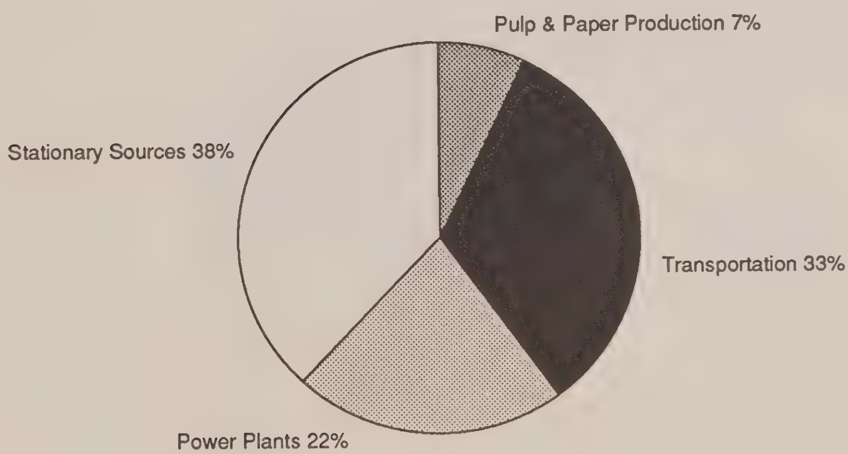
4 *Canadian Emissions Inventory of Common Air Contaminants (1985)*, A. Kostelz and M. Deslauriers, Environment Canada, Environmental Protection Series, Report EPS 5/AP/3, March, 1990.

Figure 11-2
Canadian energy-related sources of CO_2 by fuel type



Source: *National Inventory of Sources and Emissions of Carbon Dioxide,* A.P. Jaques, Environment Canada, Environmental Protection Series, EPS 5/AP/2, May, 1990.

Figure 11-3
Canadian energy-related sources of CO_2 by sector



Source: *National Inventory of Sources and Emissions of Carbon Dioxide,* A.P. Jaques, Environment Canada, Environmental Protection Series, EPS 5/AP/2, May, 1990.

from energy-related sources, primarily from the combustion of fossil fuels. The remainder is from industrial processes and miscellaneous non-energy sources.

The principal source of NO_x emissions in Canada is the transportation sector, which contributes 66 percent of energy-related emissions of this substance (Figure 11-4). That 66 percent is composed of 26 percentage points from gasoline vehicles, 28 percentage points from diesel vehicles and 12 percentage point from railways, boats, aircraft and other vehicles. Combustion from power plants and other stationary sources accounts for 14 percent and 19 percent respectively of total NO_x emissions, while oil and gas processing accounts for about 1 percent.

Volatile Organic Compounds (VOC)

VOC occur both naturally and as a result of human activities. Natural sources of VOC include seepage from oil and gas fields, volcanoes, vegetation and bacterial processes. Overall, natural sources are believed to contribute minimally to total emissions, although precise data are not available.

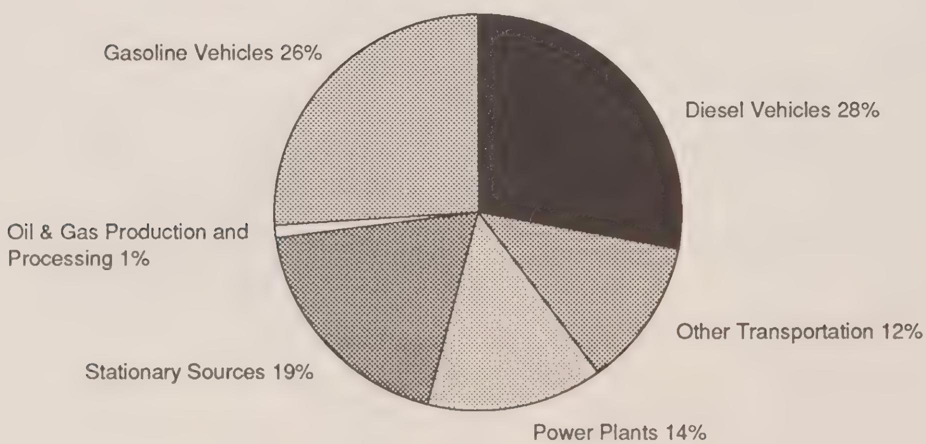
The majority of VOC emissions in Canada are produced from man-made sources, mainly fugitive emissions[1] and secondarily from the incomplete combustion of fossil fuels. Total Canadian VOC emissions in 1985 were almost 1 900 kilotonnes[2], with solvent use and petrochemical industry processes being the most important non-energy sources.

The energy sector accounts for over 1 000 kilotonnes, or about 60 percent of VOC emissions in Canada from human activities. The transportation sector is particularly important, accounting for almost 70 percent of energy-related emissions, as follows: gasoline vehicles - 54 percent, diesel vehicles - 5 percent, and other transportation

1 Fugitive emissions are unintentional releases of gases from instruments, storage and loading facilities, and fuel marketing activities, and are equivalent to evaporative losses.

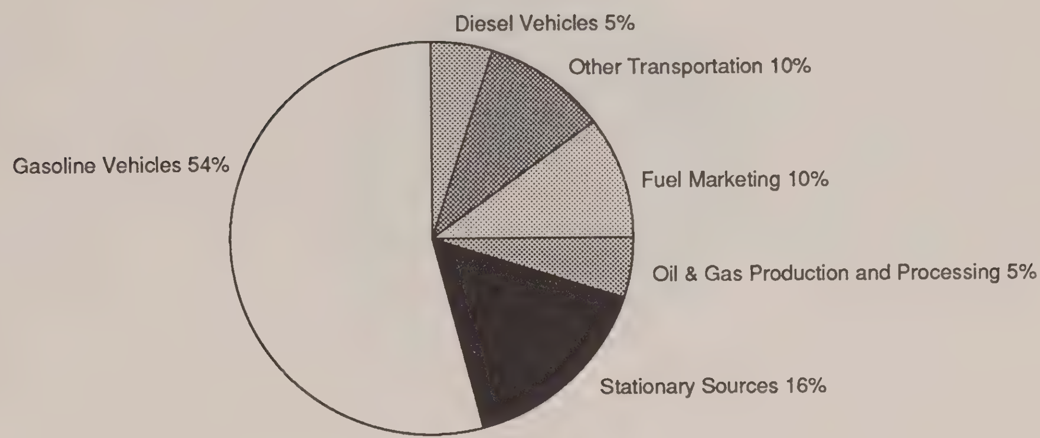
2 *Canadian Emissions Inventory of Common Air Contaminants (1985)*, A. Kostelz and M. Deslauriers, Environment Canada, Environmental Protection Series, Report EPS 5/AP/3, March, 1990.

Figure 11-4
Canadian energy-related sources of NO_x



Source: *Canadian Emissions Inventory of Common Air Contaminants (1985)*, A. Kostelz and M. Deslauriers, Environment Canada, Environmental Protection Series. Report EPS 5/AP/3, March, 1990.

Figure 11-5
Canadian energy-related sources of VOC



Source: *Canadian Emissions Inventory of Common Air Contaminants (1985),* A. Kostelz and M. Deslauriers, Environment Canada, Environmental Protection Series. Report EPS 5/AP/3, March, 1990.

sources - 10 percent. Other important sources of VOC are stationary sources and power plants (16 percent). Fuel marketing operations account for another 10 percent (Figure 11-5).

Methane (CH_4)

The global atmospheric concentration of CH_4 is estimated to have more than doubled during the last three centuries and is currently increasing at a rate of about one percent per year.[1] There is considerable uncertainty about the sources of atmospheric CH_4, and observed increases are probably related to increases in the number of sources as well as changes in the chemistry of the lower atmosphere. Increases in agricultural sources, particularly rice cultivation and animal husbandry, have probably been the most important factors, but emissions from landfills and coal seams could also play an important role in the future. On the other hand, the contribution of CH_4 from energy-related fugitive emissions and from fossil fuel combustion world-wide is considered to be relatively small.

In Canada, estimated emissions of CH_4 from human activities are some 3 805 kilotonnes as compared to natural sources of CH_4 such as wetlands, which are thought to emit about 24 000 kilotonnes annually. Forest fires and wild animals also produce CH_4, with estimated annual emissions of about 980 kilotonnes and 150 kilotonnes respectively.[2]

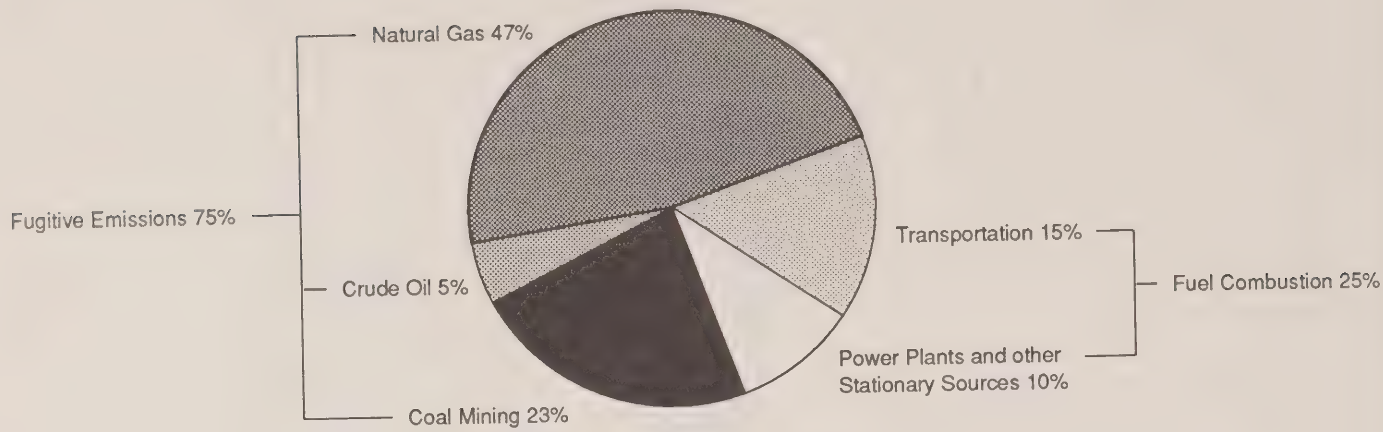
It must be emphasized that CH_4 emission rates from many sources are poorly understood. Additional research may help to resolve some of these problems, however. According to available information, the majority of Canadian CH_4 emissions from human activities are from non-energy sources; in particular, landfill sites (49 percent), large animals (23 percent) and manure (9 percent). The energy sector accounts for about 16 percent of total CH_4 emissions from human activities.

Within the energy sector, fugitive emissions of natural gas from pipelines, oil and gas production, and releases of CH_4 from coal seams during mining are the largest

1 *Report on Reducing Greenhouse Gas Emissions*, Federal/Provincial/ Territorial Task Force on Energy and the Environment, August, 1989.

2 *Greenhouse Gas Emissions, Estimates for Canada*, February 1991, A.P. Jaques, Environment Canada.

Figure 11-6
Canadian energy-related sources of CH_4



Source: *Greenhouse Gas Emissions, Estimates for Canada,* A.P. Jaques, Environment Canada, February 1991.

sources of CH_4, accounting for approximately 75 percent of the total emissions from the energy sector. Combustion-related emissions from the transportation sector (15 percent) and from stationary sources (10 percent) account for the remaining emissions (Figure 11-6).

Sulphur Dioxide (SO_2)

Total Canadian emissions of SO_2 were approximately 3 700 kilotonnes in 1985.[1] Non-energy sources of SO_2 account for about 55 percent of total SO_2 emissions. Of that amount, the majority is generated by non-ferrous smelters which process high-sulphide ores to produce metals such as copper or nickel. The remainder is produced by lead and zinc smelting, iron ore processing and chemical pulping.

The energy sector accounts for about 45 percent of total Canadian SO_2 emissions, or about 1 600 kilotonnes (Figure 11-7). The combustion of fuels containing sulphur accounts for approximately 1 000 kilotonnes of SO_2 emissions annually. The principal combustion-related source of SO_2 is thermal generating stations (mainly coal-fired) which account for about 45 percent of Canadian emissions from the energy sector. Oil and gas processing, which involves the chemical removal of sulphur and is not combustion-related, accounts for 32 percent of energy-related emissions, other stationary combustion sources such as refineries and industrial boilers contribute 17 percent, and the transportation sector contributes 6 percent.

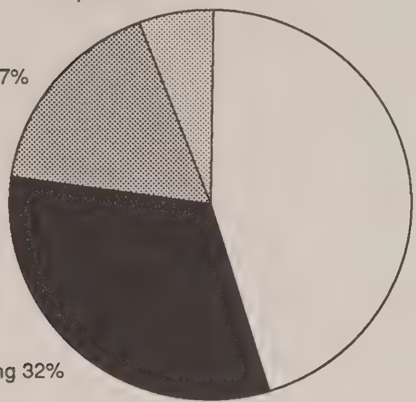
In the sections that follow, we present our estimates of emissions in the Control Case for the gases discussed above, except for methane for which there is not yet sufficient consensus to allow us to establish reliable estimates.

11.2 Emissions of Carbon Dioxide

Energy-related emissions of CO_2 included in this report are those from primary energy demand, including those arising from combustion of fuels to produce electricity, and from natural gas and synthetic crude oil production.

1 *Canadian Emissions Inventory of Common Air Contaminants (1985),* A. Kostelz and M. Deslauriers, Environment Canada, Environmental Protection Series, Report SPE 5/AP/3, March, 1990.

Figure 11-7
Canadian energy-related sources of SO_2



Source: *Canadian Emissions Inventory of Common Air Contaminants (1985),* A. Kostelz and M. Deslauriers, Environment Canada, Environmental Protection Series. Report EPS 5/AP/3, March, 1990.

11.2.1 Emissions of CO_2 from Primary Energy Demand

This section discusses the emissions of CO_2 from primary energy demand, that is from combustion of fossil fuels for end use demand (for example, gasoline, fuel oils, natural gas), and from combustion of fuels to produce and distribute these fuels, steam and electricity. These estimates of CO_2 emissions are derived by applying the appropriate emissions factors (in Appendix Table A11-1) to the estimates of energy demand from the Control Case (Appendix Tables A4-3 and A4-5). Table 11-3 shows the level of CO_2 emissions by sector and fuel for selected years (see Appendix Table A11-4 for more detail on CO_2 emissions). The pattern of CO_2 emissions is directly related to the pattern of end use fuel consumption, and to the mix of fuels used in the production and distribution of end use energy, particularly electricity.

By the year 2010, total CO_2 emissions from primary energy sources are about 624 000 kilotonnes, or 24 percent above the 1989 level. (It should be noted that emissions in 1989 are unusually high as a result of cold weather and increased reliance on fossil fuels for electricity generation.) Over the projection period, total CO_2 emissions from primary energy grow at 1 percent per year, slightly below primary energy demand growth of 1.2 percent. This somewhat slower growth reflects a shift in the shares of end use demand towards electricity: its share of end use demand increases from 20 percent in 1989 to 22 percent by 2010. In turn, the share of electricity generated from hydro and nuclear sources, which do not emit CO_2, increases over the projection period.

The contributions to CO_2 emissions by sector change through the projection period, reflecting both a shift to electricity, and the increasing use of coal for bitumen projects in the industrial sector. In 1989 residential emissions (excluding emissions related to the sector's electricity use) amounted to 11.5 percent of total CO_2 emissions. This share declines to 9 percent by 2010, as the share of electricity in residential end use demand increases. Commercial sector emissions (excluding electricity) account for between 5 and 6 percent of total primary CO_2 emissions throughout the study period. The industrial share (excluding electricity) of CO_2 emissions rises from about 27 percent in 1989 to 32 percent by 2010, as the share of coal, coke and coke oven gas in industrial end use demand increases from 9 percent in 1989 to almost 13 percent by the year 2010. Transportation's

Table 11-3

Emissions of Carbon Dioxide from Primary Energy Demand

(kilotonnes)

	1989	2000	2010
Residential	57975	57182	56738
Commercial	27889	30025	31937
Industrial	134529	159179	199311
Transportation	134251	140987	149911
Own Use	42913	50827	56396
Electricity and Steam Generation	103616	108499	129754
Total From Primary Energy	**501173**	**546699**	**624046**
Oil	215390	219749	254031
Natural Gas	110821	126665	130768
LPG	6364	7077	7880
Coal, Coke	117478	139239	175974
Renewables	50179	53324	54432
Other	941	645	961

share declines slightly (from 27 percent in 1989 to 24 percent in 2010), as energy demand in this sector grows less rapidly than in some other sectors. The shares of emissions related to the production and distribution of end use energy demand, excluding electricity, is relatively stable at 9 percent. Emissions from electricity generation account for 20.5 percent of total CO_2 emissions throughout the projection period, despite growth in electricity demand of 1.6 percent per year, as the importance of hydro and nuclear generation increases over time.

On a sectoral basis, most of the CO_2 emissions are attributable to the industrial sector which accounts for 32 percent in 2010, even excluding its electricity related emissions, while oil products account for the largest share on a fuel basis, 41 percent in 2010, followed by coal at 28 percent.

11.2.2 Provincial Disaggregation of Emissions of CO_2 From Electricity Supply

The CO_2 emissions discussed in the preceding section included those related to electricity supply. In this section we provide a provincial disaggregation of the CO_2 emissions from utility electricity supply.

Our projection of CO_2 emissions from utility electricity supply by province and generation type is provided in Table 11-4. These emission estimates are based on projected fossil fuel-fired plant generation (from data in section 5.3) multiplied by the corresponding plant emission factors. Where possible, the emission data was obtained through consultation with provincial utilities. Emissions from non-utility generation are considered negligible.

Table 11-4 shows that generating plants in provinces such as Alberta, Ontario, Saskatchewan, Nova Scotia, and New Brunswick, which are made up predominantly of fossil fuel-fired thermal plants, are all major emitters of CO_2. Generating plants in other provinces also emit CO_2 into the atmosphere but are not major contributors. They are Quebec, Manitoba and British Columbia (which are primarily hydro systems), and Newfoundland, Prince Edward Island, and the Yukon and Northwest Territories (which burn fossil fuels but are relatively small in size).

Our projections show an overall increase of CO_2 emissions due to utility generation in Canada of 3 percent between 1989 and 2000, and 24 percent between 1989 and 2010. Total emission of CO_2 from utility electricity supply are projected to increase from 99 000 kilotonnes in 1989 to 122 000 kilotonnes in 2010. Provinces such as Alberta, New Brunswick, and Nova Scotia, that are planning to meet anticipated load growth with coal- or oil-fired generation, show the most rapid increase in CO_2 emissions over the study period. For Ontario, although relying heavily on nuclear generation to meet the projected demand, we also see a substantial

Table 11-4
Emissions of CO2 from Utility Electricity Supply
(in kilotonnes)

		1989[a]	2000	2010
Newfoundland/Labrador	Coal	0	0	0
	Oil	1 597	226	866
	Natural Gas	0	0	0
	TOTAL	1 597	226	866
Prince Edward Island	Coal	0	0	0
	Oil	90	121	146
	Natural Gas	0	0	0
	TOTAL	90	121	146
Nova Scotia	Coal	6 637	9 968	11 454
	Oil	2 629	686	957
	Natural Gas	0	0	0
	TOTAL	9 266	10 654	12 410
New Brunswick	Coal	2 646	6 800	6 800
	Oil	5 898	4 436	5 671
	Natural Gas	0	0	0
	TOTAL	8 544	11 236	12 470
Quebec	Coal	0	0	0
	Oil	1 038	394	1 216
	Natural Gas	0	0	126
	TOTAL	1 038	394	1 342
Ontario	Coal	26 991	25 050	35 320
	Oil	1194	11	198
	Natural Gas	0	0	201
	TOTAL	28 185	25 061	35 719
Manitoba	Coal	479	1	0
	Oil	24	0	0
	Natural Gas	0	0	0
	TOTAL	503	1	0
Saskatchewan	Coal	11 978	12 009	11 871
	Oil	0	0	0
	Natural Gas	271	54	29
	TOTAL	12 249	12 062	11 901
Alberta	Coal	32 724	39 726	44 004
	Oil	11	60	60
	Natural Gas	2 289	1 032	1 421
	TOTAL	35 024	40 818	45 484
British Columbia	Coal	0	0	0
	Oil	117	2	89
	Natural Gas	2 244	316	1 191
	TOTAL	2 361	318	1 279
Yukon Territories	Coal	0	0	0
	Oil	28	76	133
	Natural Gas	0	0	0
	TOTAL	28	76	133
Northwest Territories	Coal	0	0	0
	Oil	169	286	378
	Natural Gas	0	0	0
	TOTAL	169	286	378
CANADA TOTAL	Coal	81 455	93 554	109 449
	Oil	12 796	6 298	9 712
	Natural Gas	4 803	1 401	2 968
	TOTAL	99 055	101 253	122 128

Note: The numbers in this table have been rounded.
[a] 1989 figures based on actual generation figures converted using estimated emission factors.

increase in CO_2 emissions as reliance on current thermal units increases. Of all the provinces, only Saskatchewan shows a slight decrease (of 3 percent) in CO_2 emissions over the 1989 to 2010 period. This is due to the very low load growth projected for this province, coupled with increased generation available from new, higher efficiency power plants.

The Control Case incorporates little in the way of measures to mitigate CO_2 emissions from thermal generation plants. However, utility demand management programs which we expect to be in place are reflected in these projections and will dampen demand, resulting in a corresponding decrease in CO_2 emissions. The nuclear generation development in Ontario, and hydro generation development in British Columbia, Manitoba, and Quebec, which are included in our Control Case do not contribute to CO_2 emissions. However, these generation types do have other environmental impacts which are not addressed in this study.

11.2.3 Emissions of CO_2 from Natural Gas and Synthetic Crude Oil Production

This section discusses upstream CO_2 emissions from the natural gas industry as well as those emissions from bitumen production and upgrading which are not accounted for in section 11.2.1. Emissions related to natural gas result from fuel combustion associated with production and processing, as well as raw CO_2 released directly into the atmosphere during production and processing. Sources of emissions related to oil sands activity which are not addressed in section 11.2.1 include the combustion of lease fuel (or field gas) for steam

generation at in situ bitumen recovery projects, the combustion of process gas and coke used as fuel at oil sands plants and the use of feedstock gas for the bitumen upgrading process.

Lease fuel is gas produced as a result of the heating of bitumen during in situ recovery processes. Process gas is a light hydrocarbon gas which is produced in the coking and hydrotreating units at oil sands plants and, after sweetening, is used as fuel. Coke, a component of bitumen, is produced as a result of the primary upgrading of bitumen and is also used as fuel at these plants. The conversion of natural gas (feedstock gas) to hydrogen also results in byproduct CO_2 emissions.

Emissions of CO_2 from these sources in 1989 are estimated to be 32 000 kilotonnes. Of this, natural gas production and processing accounts for about 68 percent, raw CO_2 approximately 17 percent and those sources related to oil sands activity listed above about 15 percent.

The projection of CO_2 emissions provided in this section was developed in cooperation with the ERCB. The projections were derived using our Control Case natural gas supply projections for Alberta and a CO_2 emissions model developed by the ERCB. Based on the emissions estimated for Alberta, we projected emissions from all Canadian natural gas production projection.[1] To derive CO_2 emissions arising from combustion, energy use is converted to carbon dioxide emissions by applying an appropriate emissions factor for the fuel being used. An estimate of the amount of raw CO_2 released to the atmosphere during gas production and processing was based on available data regarding the current CO_2 content of natural gas reserves.

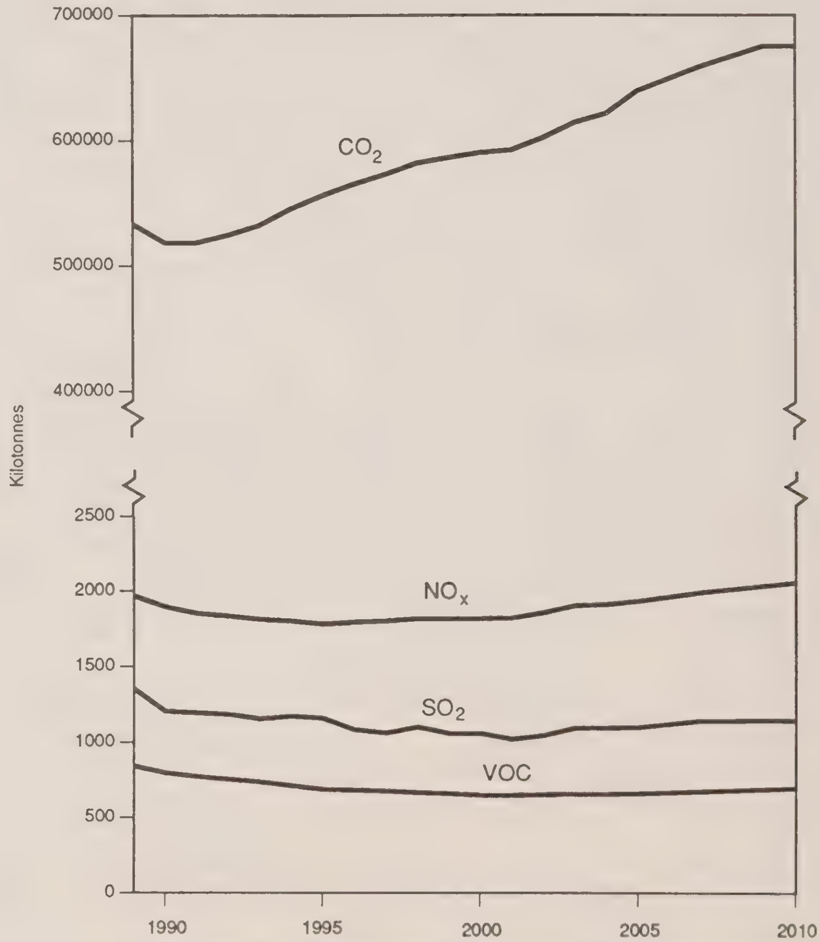
Emissions of CO_2 from these sources are expected to increase from about 34 000 kilotonnes in 1990 to about 51 000 kilotonnes by 2010. This increase is approximately in proportion to the projected increase in natural gas and synthetic crude production.

11.2.4 Summary of Emissions of CO_2

We project energy-related emissions of CO_2 to increase at an average annual rate of about 1.1 percent over the study period, reaching 675 000 kilotonnes in 2010 (see Figure 11-8 and Appendix Table A11-4). This represents an increase of

1 The ERCB and Alberta Energy model was considered to be the most appropriate basis for projecting emissions of CO_2 and certain other greenhouse gases because it is a comprehensive and well-established model which has been used extensively to develop provincial emissions projections.

Figure 11-8
Projected Gaseous Emissions in Canada*



*Each of these lines has been drawn independently; i.e., they have not been "stacked". For example, in 1989 VOC emissions are 844 kilotonnes and SO_2 emissions are 1355 kilotonnes.

142 000 kilotonnes as compared to the emissions level in 1989.

The industrial sector comprises approximately 45 percent of the increase in emissions and the electricity and steam generation sector 18 percent, largely due to the increased use of coal, coke and coke oven gas. Emissions of CO_2 from natural gas and synthetic crude oil production comprise 12 percent of the increase in CO_2 emissions, largely due to growth in natural gas production.

11.3 Emissions of Nitrogen Oxides

Energy-related emissions of NO_x included in this report also are those arising from primary energy demand, including those from electricity generation, and from natural gas and synthetic crude oil production.

11.3.1 Emissions of NO_x From Primary Energy Demand

Emissions of NO_x from fuel combustion result mainly from the use of oil products and coal. To derive the estimates of NO_x emissions, we applied emissions factors to fuel use in the Control Case. Emissions factors are applied to the fuel consumption of each sector with the exception of road transportation. As legislation provides that all cars and trucks must be equipped with catalytic converters which reduce emissions of NO_x and VOC, the emissions from this sector must be calculated in a different manner. The standards for road transportation emissions of NO_x and VOC are specified in grams per mile. The characteristics of the vehicle's engine and the combustion process affect the level of NO_x and VOC emissions. A vehicle which is extremely fuel efficient may not be able to meet a specific standard for NO_x and VOC, due to its combustion process, while one which is less efficient, with a different combustion process may achieve the standard. It is not possible to link vehicle fuel combustion in the road sector directly to NO_x and VOC emissions levels, as can be done for other sectors. As a result NO_x and VOC emissions are a function of the standards for new vehicles in each year, the mix of the stock (with respect to age), and the distance driven by the vehicles.

We have developed estimates of NO_x and VOC emissions factors for the road sector with the assistance of Environment Canada, using information on our road vehicle stock and legislated emissions standards (see Appendix Table A11-2 for NO_x and A11-3 for VOC). These emissions factors are applied to the distance driven by each category of car and truck stock (e.g. small and large cars, and trucks by size and fuel use).

In 1989, of an estimated 1765 kilotonnes emissions of NO_x from fuel combustion, 937 kilotonnes resulted from gasoline and diesel use in the transportation sector, and 308 kilotonnes from oil and coal use in the industrial sector. Fuels for electricity generation contributed another 262 kilotonnes.

Our projection of NO_x emissions reflects current legislated standards for vehicle emissions, which include more stringent emissions controls on new model cars and trucks over the next few years. We have not included any further improvements beyond the existing legislation, but as older vehicles are retired and as new vehicles, with improved emissions standards, make up a larger proportion of the stock, there is a decline in NO_x emissions from this source. Thus, NO_x emissions from transportation fuel use decline absolutely, from 937 kilotonnes in 1989 to 692 kilotonnes in 2010, despite the fact that transportation energy use in the year 2010 is 12 percent above its 1989 level. (See Appendix Table A11-5 for detailed emissions by sector.)

NO_x emissions from the industrial sector increase from 308 kilotonnes in 1989 to 479 kilotonnes in 2010. NO_x emissions from electricity generation increase only slightly relative to 1989 levels, from 262 kilotonnes to 307 kilotonnes in 2010. The decline in NO_x emissions from the transportation sector are offset by 2010 by increases in emissions from other sectors; total NO_x emissions from primary energy demand by 2010 are slightly above their 1989 level.

11.3.2 Provincial Disaggregation of Emissions of NO_x From Electricity Supply

The NO_x emissions discussed in the preceding section included those related to electricity generation. In this section we provide a provincial disaggregation of CO_2 emissions from utility electricity supply.

Table 11-5 shows the provinces that are the largest emitters of NO_x are those that rely heavily on fossil fuel-fired generation. Our projections, calculated using the same method described in section 11.2.2 for CO_2, show an overall increase from the 1989 levels of NO_x emissions of only 1 percent by the year 2000, and 17 percent by the year 2010. A large portion of the increase in NO_x emissions during the final decade of the study period is attributed to the provinces of Alberta, New Brunswick, Ontario

Table 11-5
Emissions of NOx from Utility Electricity Supply

(in kilotonnes)

		1989[a]	2000	2010
Newfoundland/Labrador	Coal	0.0	0.0	0.0
	Oil	3.0	0.2	0.6
	Natural Gas	0.0	0.0	0.0
	TOTAL	3.0	0.2	0.6
Prince Edward Island	Coal	0.0	0.0	0.0
	Oil	0.4	0.5	0.4
	Natural Gas	0.0	0.0	0.0
	TOTAL	0.4	0.5	0.4
Nova Scotia	Coal	21.1	29.8	31.6
	Oil	7.3	1.9	2.6
	Natural Gas	0.0	0.0	0.0
	TOTAL	28.4	31.7	34.2
New Brunswick	Coal	5.3	12.8	12.8
	Oil	24.6	19.2	24.0
	Natural Gas	0.0	0.0	0.0
	TOTAL	29.9	32.0	36.8
Quebec	Coal	0.0	0.0	0.0
	Oil	5.3	8.1	9.6
	Natural Gas	0.0	0.0	0.0
	TOTAL	5.3	8.1	9.6
Ontario	Coal	60.2	54.8	77.6
	Oil	8.3	0.1	1.5
	Natural Gas	0.0	0.0	0.0
	TOTAL	68.5	54.9	79.0
Manitoba	Coal	1.7	0.0	0.0
	Oil	0.0	0.0	0.0
	Natural Gas	0.0	0.0	0.0
	TOTAL	1.7	0.0	0.0
Saskatchewan	Coal	35.0	34.6	33.9
	Oil	0.0	0.0	0.0
	Natural Gas	0.8	0.0	0.0
	TOTAL	35.7	34.6	33.9
Alberta	Coal	70.4	91.4	92.9
	Oil	0.0	1.2	1.2
	Natural Gas	6.6	3.0	3.7
	TOTAL	77.1	95.7	97.8
British Columbia	Coal	0.0	0.0	0.0
	Oil	2.4	0.0	0.6
	Natural Gas	6.0	0.8	3.2
	TOTAL	8.4	0.8	3.7
Yukon Territories	Coal	0.0	0.0	0.0
	Oil	0.6	1.6	2.7
	Natural Gas	0.0	0.0	0.0
	TOTAL	0.6	1.6	2.7
Northwest Territories	Coal	0.0	0.0	0.0
	Oil	3.5	5.9	7.7
	Natural Gas	0.0	0.0	0.0
	TOTAL	3.5	5.9	7.7
CANADA TOTAL	Coal	193.7	223.4	248.7
	Oil	55.4	38.6	51.0
	Natural Gas	13.4	3.9	6.9
	TOTAL	262.4	265.9	306.6

Note: The numbers in this table have been rounded
[a] 1989 figures based on actual generation figures converted using estimated emission factors.

and Nova Scotia where the generation expansion programs are based largely on additions of new fossil fuel-fired capacity. Nevertheless, the Control Case does incorporate the retirement of older, low-efficiency units and the installation of new fossil fuel-fired low NO_x burners (such as the circulating fluidized bed technology planned for the Point Aconi plant in Nova Scotia). For Saskatchewan we show a decrease in NO_x emissions of 6 percent over the study period. Our low demand projections for this province, coupled with a greater reliance on the new Shand coal-fired plant with its low NO_x burners and reduced utilization of the older, less efficient thermal plants, account for this decrease.

11.3.3 Emissions of NO_x from Natural Gas and Synthetic Crude Oil Production

This section discusses NO_x emissions from upstream natural gas production and processing and oil sands sources which are not accounted for in section 11.3.1. Included are emissions released as a result of combustion during the production and processing of natural gas, as well as emissions resulting from the combustion of lease fuel for in situ bitumen production and of process gas and coke for the upgrading of bitumen to synthetic crude oil.

Emissions of NO_x in 1989 from these sources are estimated to be 203 kilotonnes. Natural gas production and processing accounts for about 96 percent of these emissions, while lease fuel, process gas, coke and feedstock gas used in bitumen production and upgrading to synthetic crude accounts for the remaining 4 percent.

As was the case for projections of CO_2 emissions, the projection of NO_x emissions provided in this section was developed in cooperation with the ERCB. The projections were derived using our Control Case natural gas supply projections and a NO_x emissions model developed by the ERCB. Based on the emissions estimated for Alberta, we projected emissions from all Canadian natural gas production. The emission factors used in the determination of NO_x emissions were based on Environment Canada and U.S. EPA data. Sources of emissions include incinerators, boilers, heaters and compressors. Emissions of NO_x from these sources are expected to increase, as natural gas and bitumen production increases, from about 212 kilotonnes in 1990 to about 274 kilotonnes per year by 2010. The increase in emissions is approximately in proportion to the expected increase in production.

11.3.4 Summary of Emissions of NO_x

We project total emissions of NO_x (Figure 11-8) to increase only slightly over the study period, from 1 970 kilotonnes in 1989 to 2 050 kilotonnes in 2010 or 0.2 percent per year. The industrial sector exhibits a steady growth in NO_x emissions over the study period. Emissions from natural gas and synthetic crude production also increase, while the transportation sector emissions are expected to decrease substantially by the year 2000 before rising slightly again to the year 2010.

Only current mitigation procedures were taken into account in the development of the projections; more stringent controls or newer technologies, as referred to in the Management Plan for NO_x and VOC released by the Canadian Council of Ministers of the Environment in November 1990, have not been included.

11.4 Emissions of Volatile Organic Compounds

Energy-related emissions of VOC included inthis report are those arising from primary energy demand and from natural gas, conventional crude oil and bitumen production.

11.4.1 Emissions of VOC from Primary Energy Demand

Emissions of VOC, like NO_x, result largely from combustion of oil products, coal and wood. We derive our estimates of VOC emissions by applying emissions factors to fuel consumption in each sector except road transportation. (See section 11.3.1 for a discussion of emissions factors for NO_x and VOC for road transportation.) In 1989 total VOC emissions from primary fuel combustion totalled 844 kilotonnes, of which 676 kilotonnes originated in the transportation sector, and 125 kilotonnes from residential energy use. Over the projection period, VOC emissions from transportation sources are expected to decrease, as new standards (i.e. current legislation for future model years) affect the nature of the vehicle stock, and related VOC emissions. By the year 2010, VOC emissions from transportation are estimated to be about 509 kilotonnes, and total emissions from primary demand 693 kilotonnes, some 18 percent below the 1989 level. The impact of legislated standards in the transportation sector is to steadily reduce emissions to 471 kilotonnes by the year 2000, although the impact of a growing car and truck stock causes transportation-related VOC emissions to increase thereafter. (See Appendix Table A11-6).

11.4.2 Emissions of VOC from Natural Gas, Conventional Crude Oil and Bitumen Production

Emissions of VOC related to natural gas production, transmission and distribution have been identified in previous work by Environment Canada and Energy Mines and Resources.[1] However, emissions related to the production of conventional crude oil and bitumen were not accounted for in this work. The emission factors and estimates of VOC emissions are now under review by Environment Canada and EM&R, in light of new VOC emissions information which has recently become available. Due to the lack of reliable available emissions data, we have decided not to quantify VOC emissions from these sources in this report. While emissions resulting from primary demand can be identified on the basis of documented data, further study is required to enhance the understanding of VOC emissions from upstream sources.

11.4.3 Summary of Emissions of VOC

In this report we have estimated only those emissions arising from primary energy demand.

VOC emissions are projected to decrease between 1989 and 2010

1 *Emissions Factors for Greenhouse and Other Gases by Fuel Type: An Inventory*, Ad Hoc Committee on Emission Factors, Energy Mines and Resources, December 1990.

at an annual rate averaging 0.9 percent (Figure 11-8), as a result of the continuing displacement of vehicles without VOC-control equipment by new vehicles, despite continued growth in the car and truck stock.

As for NO_x, any additional emissions-reduction initiatives discussed in the Management Plan for NO_x and VOC released by the Canadian Council of Ministers of the Environment in November 1990 have not been taken into consideration in our projections of VOC emissions.

11.5 Emissions of Methane

Methane emissions included in this report are those related only to the production and transportation of natural gas, conventional crude oil and bitumen and to the production of coal.

11.5.1 Emissions of CH_4 from Natural Gas, Conventional Crude Oil and Bitumen Production and Transportation and Coal Production

Like emissions of VOC, upstream emissions of CH_4 are thought to result primarily from the production of conventional crude oil and natural gas. To a lesser extent, CH_4 emissions also result from the production of bitumen and the transportation of hydrocarbons.

Emissions of CH_4 from natural gas, conventional crude oil and bitumen production and transportation have not been quantified, for the same reasons that projections of upstream VOC emissions has not been developed for this report.

Methane is the most significant greenhouse gas emission associated with coal mining. Fugitive emissions from underground mines are much greater than from surface mines on a per tonne of coal mined basis. Coal found at greater depth, and therefore greater pressure, generally contains more methane. As pressure is reduced, methane is released from the coal. For this reason, the shallow coal deposits of Western Canada contain less methane than the deeper deposits found in Atlantic Canada. Methane ventilation and drainage are the two means of controlling the concentration of methane in underground mines. Methane drainage involves degasifying the coal before mining, thereby reducing the ventilation air required. Methane collected by these means is generally released to the atmosphere.

A projection of fugitive CH_4 emissions from coal mining is not included in this report, because currently published estimates are highly variable, ranging from 79 to 360 kilotonnes, and do not in our view provide a sufficiently reliable basis for the projection of future emissions.

11.6 Emissions of Sulphur Dioxide

Energy-related emissions of SO_2 included in this report are those arising from utility electricity generation and those related to natural gas and bitumen production.

11.6.1 Emissions of SO_2 From Electricity Supply

We project a marked decrease over the study period in emissions of SO_2 from electric utility generation (Table 11-6). An overall reduction from 1989 levels of 39 percent by the year 2000, and of 32 percent by the year 2010, demonstrates the major commitment of the provincial utilities (particularly those whose generation is primarily thermal) to significantly reduce emissions of SO_2. This effort is especially apparent in the provinces of Nova Scotia, New Brunswick, and Ontario, where lakes, forests, and soils are sensitive to such acidic depositions. As demand for electricity grows over the study period, installation of desulphurization equipment at existing and new generation stations, and the utilization of clean coal technology are expected to contribute greatly to the projected decrease in SO_2 emissions.

The province of Alberta, with a demand four times as large as that of Nova Scotia, contributes about the same amount of SO_2 into the atmosphere (i.e. approximately 160 kilotonnes annually), even though generation in both of these provinces is predominantly coal-fired. The low sulphur sub-bituminous coals used for thermal generation in Alberta as opposed to high sulphur bituminous coals used in Nova Scotia is the reason for Alberta's relatively low SO_2 emissions. Nonetheless, some increased use of desulphurization equipment is likely to be utilized to further curb SO_2 emissions in this province.

11.6.2 Emissions of SO_2 from Natural Gas Production and Bitumen Production

Included in this section are emissions of SO_2 resulting from natural gas production and processing and from the production and processing of bitumen. Emissions of SO_2 associated with conven-

Table 11-6
Emissions of SO_2 from Utility Electricity Supply

(in kilotonnes)

		1989[a]	2000	2010
Newfoundland/Labrador	Coal	0.0	0.0	0.0
	Oil	22.7	0.7	3.0
	TOTAL	22.7	0.7	3.0
Prince Edward Island	Coal	0.0	0.0	0.0
	Oil	1.1	1.3	0.4
	TOTAL	1.1	1.3	0.4
Nova Scotia	Coal	112.0	136.1	141.8
	Oil	23.3	5.9	8.0
	TOTAL	135.3	142.1	149.8
New Brunswick	Coal	129.5	16.4	16.4
	Oil	95.8	70.9	88.1
	TOTAL	225.3	87.4	104.6
Quebec	Coal	0.0	0.0	0.0
	Oil	2.9	0.0	2.8
	TOTAL	2.9	0.0	2.8
Ontario	Coal	294.8	80.2	113.0
	Oil	2.8	0.0	0.4
	TOTAL	297.6	80.2	113.4
Manitoba	Coal	2.4	0.0	0.0
	Oil	0.0	0.0	0.0
	TOTAL	2.4	0.0	0.0
Saskatchewan	Coal	86.7	79.2	72.4
	Oil	0.0	0.0	0.0
	TOTAL	86.7	79.2	72.4
Alberta	Coal	115.9	152.5	163.2
	Oil	0.0	0.0	0.0
	TOTAL	115.9	152.5	163.2
British Columbia	Coal	0.0	0.0	0.0
	Oil	0.0	0.0	0.0
	TOTAL	0.0	0.0	0.0
Yukon Territories	Coal	0.0	0.0	0.0
	Oil	0.0	0.0	0.0
	TOTAL	0.0	0.0	0.0
Northwest Territories	Coal	0.0	0.0	0.0
	Oil	0.0	0.0	0.0
	TOTAL	0.0	0.0	0.0
CANADA TOTAL	Coal	741.4	464.4	506.9
	Oil	148.6	78.9	102.7
	TOTAL	890.0	543.3	609.5

Notes: The numbers in this table have been rounded.
SO2 emissions from natural gas are consiered neglible.
[a] 1989 figures based on actual generation figures converted using estimated emission factors.

tional crude oil production are relatively insignificant and estimates have not been included in this report.

For the natural gas industry, SO_2 emission levels are determined primarily by the production levels and sulphur content of natural gas, as well as the level of sulphur recovery obtained during processing. Natural gas plants that process sour gas emit SO_2 as part of the sulphur recovery process. Flaring of sour gas at processing plants and sour gas well testing also contribute to SO_2 emissions from natural gas. For bitumen production and upgrading, SO_2 emission levels are largely determined by the processing technique which is used.

Sulphur is recovered from natural gas plants at a rate of about 98 percent and the sulphur recovered or left in the coke at oil sands and in situ bitumen recovery projects is approximately 88 percent. However, there is no sulphur recovery from sour gas flaring or testing.

The upstream emissions of SO_2 in 1989 are estimated to be about 465 kilotonnes.

Our projection of SO_2 emissions was developed in cooperation with the ERCB. The projections were derived using our Control Case natural gas supply projections for Alberta and a SO_2 emissions model developed by the ERCB. The emissions estimated for Alberta were adjusted upward to reflect the total Canadian natural gas production projection. For these projections, the expected production of natural gas is identified as being either from established reserves or from future additions. The sulphur content of established reserves and the

existing ERCB guidelines for sulphur recovery determine the expected SO_2 emissions from this source on a plant-by-plant basis. A projection of sulphur dioxide emissions from reserves additions was developed using an estimated future recovery level and an estimate of the sulphur content of future additions.

For bitumen mining projects, a projection of emissions was developed on the basis of the Control Case production estimates and the anticipated level of sulphur recovery at existing and new plants. Sulphur recovery improvements and changes in process technology expected to reduce the SO_2 emissions per unit of production were incorporated into the projections of upstream SO_2 emissions and have the effect of partially offsetting the increase in emissions arising from increased production of both natural gas and bitumen.

In total, emissions of SO_2 from these sources are expected to increase to about 531 kilotonnes per year by 2010.

11.6.3 Summary of Emissions of SO_2

Total SO_2 emissions are projected to decrease at an annual rate averaging 0.8 percent over the study period (Figure 11-8), from 1 355 kilotonnes in 1989 to 1 141 kilotonnes in 2010, as a result of the considerable reduction (by nearly one-third) of emissions from electricity generation plants. These reductions will take place mainly in the eastern provinces where emission limits have been established as a result of federal/provincial agreements for the control of SO_2 emissions.

Increased emissions of SO_2 from natural gas and bitumen production are expected to partially offset the reductions in emissions from electricity generation. However, SO_2 emissions per unit of production should decrease with improvements in emissions control technology.

11.7 Emissions Reduction Measures

In this section we examine emissions reduction measures which could be implemented over the study period but which have not been included in the Control Case because they are generally not yet commercially viable. We describe many of the available measures and provide an indication as to their possible impact on energy demand and/or gaseous emissions.

11.7.1 Measures to Reduce Energy Demand

11.7.1.1 Residential Sector

In this section, we examine the energy conservation that would result from more rapid and widespread implementation of the most efficient residential energy-using technologies, than assumed in our Control Case. Widespread use of these technologies would likely entail substantial additional costs to households buying and installing the related equipment. The potential energy savings are discussed by end use.

With respect to single-family dwellings, the most energy efficient new house currently built in Canada uses as little as 40 percent of the energy required for an R-2000 house for all heating, air conditioning and residential hot water needs, or as little as 20 percent of the energy of a house designed to meet the 1983 National Building Code (NBC) guidelines. About twice the amount of insulation is used in this highly energy efficient house as was recommended in the 1983 NBC guidelines. There are greater passive solar gains than in the average house because a glassed area adjacent to the south wall of the house preheats air for ventilation.

Windows are generally responsible for significant heat loss due to conduction through the glass and frame, as well as to air leakage. By using glass with a low emissivity (low-e) coatings, by filling the space between the inner and outer layers with argon, and by using low conduction materials in other parts of the window, the thermal resistance of windows can be greatly improved, thereby decreasing heating needs. The most efficient windows presently available have a thermal resistance of approximately 0.9 RSI[1], compared with 0.36 RSI for the models most commonly used in new buildings. Over the next few years, industry expects to produce windows with a thermal resistance in excess of 1.25 RSI.

For space heating, accelerated penetration of heat pumps, with a coefficient of performance of up to 2.7 (ratio between the amount of heat transmitted by the pump and the electricity consumed at a given temperature), would increase energy efficiency relative to the Control Case, where we have assumed only limited use of heat pumps. Integrated systems designed to recover the heat from various sources and retain it for other uses could replace furnaces,

1 RSI is thermal resistance expressed using the International System of Units (SI) ($m^2\ ^0C/W$).

water heaters, air conditioners and ventilation systems in houses. These integrated systems use heat pumps and their coefficient of performance is approximately 2.8. They are currently produced only in limited quantities for selected applications.

Highly energy efficient gas or oil furnaces are equipped with secondary heat exchangers to recover additional heat from combustion gases. The annual fuel efficiency with this type of furnace is approximately 90 percent. In our Control Case, we assumed that this type of furnace would be found in 15 to 25 percent of new houses heated by oil or gas. Widespread use of these furnaces in new housing would add further to the efficiency gains realized from the adoption of the measures described above, relating to an improved thermal envelope and increased passive solar gains.

All of the above measures would have less impact in new multifamily dwellings, since their application would be limited due to physical constraints.

It is estimated that most existing dwellings (nearly 70 percent of the single-family dwelling stock) do not now meet the NBC insulation standards proposed for new dwellings in 1978. The average efficiency of the existing housing stock could be raised to that of a new dwelling built to the 1978 standards, by applying a series of measures involving insulation and more airtight construction of the dwelling. These measures are aimed specifically at decreasing the rate of air change in dwellings by reducing air leakage in attics, doors, windows and electrical equipment attached to ceilings and walls, as well as in crawlspaces and basements. The insulation in ceilings, outside walls and basements could also be increased to the levels proposed in the Code by blowing in cellulose or placing rigid insulation in the appropriate places.

All obsolete gas or oil heating units could be replaced by high efficiency furnaces during the projection period, as compared to the Control Case, where they are generally assumed to be replaced with mid efficiency units.

In our Control Case, the average energy use per household for space heating (normalized for weather) falls by nearly 20 percent over the projection period. Without adjusting the fuel shares for space heating, implicit in the Control Case, widespread implementation of the measures described above would lead to an additional decrease in the average energy consumption for space heating of approximately 35 percent by 2010.

Energy use for water heating could be reduced by decreasing the household demand for hot water and by improving the efficiency of water heaters.

It is generally recognized that washing machines and dishwashers use most of their energy in the form of hot water. Most technological improvements for these appliances are aimed at improving hot water usage. Thermostatic valves, designed to decrease the water temperature for hot water washing to 49^{o}C by mixing hot and cold water, are among the existing technologies that apply to washing machines. Generally, when hot water leaves the water heater, it is approximately 60^{o}C. Widespread use of this technology would save energy without affecting the quality of the wash. Improved filters for collecting food particles during wash cycles and more accurate timers to control water intake would reduce the amount of hot water used in dishwashers. Accessories such as flow-filters for faucets and low flow shower heads would also substantially decrease household hot water needs.

The efficiency factor for conventional gas water heaters is approximately 52 percent. This factor can be increased to 72 percent by using water heaters equipped with submerged combustion chambers (i.e. the combustion chamber is surrounded by water).

Average energy needs for water heating could be further decreased by approximately 25 percent by 2010, as compared to the Control Case, through improved insulation of tanks and the widespread use of tested technologies such as those mentioned above, without resorting to the use of alternative technologies such as solar energy.

Even if we assumed widespread implementation of the most efficient proven technology in North America for basic household appliances, we estimate that there would be only small additional improvements relative to those already projected in the Control Case. The energy consumption standards for refrigerators and freezers that will come into effect in the 1990s correspond to the most efficient level of technology currently tested. New washing machines and dishwashers which consume much less energy than earlier models (except for energy for hot water) could, however, still be equipped with highly energy efficient motors and save even more energy. Furthermore, widespread marketing of dryers with

moisture sensors, more insulation and exhaust air recycling systems would also contribute to reducing energy consumption relative to the Control Case. Finally, with respect to air conditioning, efficiency gains could be achieved by using central units with seasonal energy efficiency of 13 to 14 (values obtained by dividing total cooling capacity during the season by the amount of energy consumed by the air conditioner) and window units with seasonal efficiencies of 10 to 12. These types of units are currently available.

In the Control Case, we assumed that compact fluorescent lights would account for 20 percent of lighting needs in 2010, reducing average energy consumption for lighting by approximately 15 percent, as compared to current use. The extent of penetration of this technology during the projection period is uncertain and ultimately depends on consumer preference. However, if we assume that this compact fluorescent technology, in its current form, satisfied 50 percent of lighting needs in 2010, average household energy use for lighting would decrease by an additional 30 percent as compared to our Control Case.

In summary, if all of the measures mentioned above were adopted by Canadian households during the projection period, we estimate that average household energy consumption would decrease by almost 45 percent by 2010, relative to 1989. As compared to our Control Case in 2010, this represents an additional decrease of nearly 30 percent.

11.7.1.2 Commercial Sector

In the Control Case we assumed that there would be relatively little adoption of highly efficient energy using technologies in the commercial sector over the projection period, and that most of the efficiency and intensity improvements would result from continued use of recent technologies, and turnover of capital stock and equipment. While the new technologies which have the broadest application and acceptance in the commercial sector are more efficient than the average for the existing stock, these technologies are not the most efficient currently available. Highly efficient (and often cost effective) technologies are available, but are not being widely used, due to the barriers discussed in Section 4.2.3.

This section contains a discussion of energy efficient technologies available to the commercial sector and estimates the percentage savings which would result from their adoption, relative to the most commonly used technologies. The discussion focuses on technologies applicable to the office and retail sub-sectors although some of these technologies also have applications in other building types. Together these two sub-sectors account for approximately 40 percent of the energy used in the commercial sector. The major end-use categories discussed are: lighting, space heating, cooling, ventilation, and refrigeration.

Fluorescent lighting accounts for most of the lighting needs in the commercial sector (not including street lighting). In retail and office buildings it accounts for about 70 to 75 percent. Reductions in electricity consumption for **lighting** can be achieved through several measures. Energy use for fluorescent lighting can be reduced with the use of low-wattage lamps, more efficient ballasts, fixtures with improved reflectivity (also known as high efficiency luminaires), lighting controls and occupancy sensors.

The options currently available for fluorescent lamps allow for a reduction in wattage to 32W, from the conventional lamp rated at 40W. The estimate of the current commercial market penetration for low-wattage lamps is 15 percent, which indicates that a large potential market for these lamps exists if barriers to use can be overcome. In Ontario and B.C, the sale of low wattage lamps was recently estimated to account for 15 percent of all fluorescent sales. Improvements in lamp technologies relate to a higher amount of krypton instead of argon filling, lamps with improved phosphor coating, and lamps with the cathode disconnect feature. Another technology consists of reduced diameter lamps which use 20 to 25 percent less power than the standard 40W lamp. Lamps of this type are most suited to new construction or major renovation since they use special fixtures.

Energy savings in lighting can also be achieved through the use of more efficient ballasts. The standard models, which still predominate in Canadian office buildings, consume 16W to power a two lamp fixture. More efficient core-coil ballasts with copper wire consume about 8W. The electricity requirement of electronic models is about 4W for a two lamp fixture. In normal service, ballasts should last 15 to 20 years. Consequently, most of the existing units will have to be replaced over our projection period.

Another way of reducing electricity requirements in lighting is to focus light on working areas with optical reflectors, which reduces the total amount of light required. The reflectivity of luminaires can be improved by using an aluminium or

silver film reflector. The optical reflector market in Canada is quite new and the technology has been available in Canada only since 1986. Compared to the standard lighting package, energy savings from reflectors depend on the reduction in lighting level that can be achieved.

Other new technologies or measures such as daylight dimming, occupancy sensors, and power reducers can bring additional savings.

One fluorescent fixture upgrade for existing buildings which would not require major retrofitting consists of a package of two 32 W lamps, with an electronic ballast and an optical reflector. Compared to the conventional system of two 40 W lamps, with standard ballast and white painted luminaire that has an input wattage of 96 W, this energy efficient package can save up to 55 percent in electricity consumption for fluorescent lighting.

More flexibility in new construction would allow the use of High Efficiency 40W lamps, electronic dimming ballasts, optical reflectors, and daylight dimming controls. Compared to the system currently in widespread use, the energy savings associated with this package is about 75 percent.

Significant savings can also be achieved in incandescent lighting. Incandescent use, particularly in general service, can be replaced by compact fluorescent bulbs and save approximately 70 percent in electricity consumption for the same application. For outdoor applications such as roadway or street lighting the use of high pressure sodium lamps as opposed to the mercury vapor type could save about 40 percent in energy. Under normal use all lamps currently in place will come to the end of their service life over the projection period and could be replaced through the normal replacement cycle by their most energy efficient counterpart.

A reduction in the overall lighting energy use by commercial buildings will increase heating requirements. It will also contribute to a reduction in cooling energy use for buildings with cooling loads.

There are several measures that can be taken to increase efficiency for **space heating**: building shell improvements by the use of superior envelope materials, window treatments and improved methods of construction; heat pump systems; and space heating system upgrades such as the installation of high efficiency burners, installation of turbulators to improve heat transfer in the boiler tubes and proper operation and maintenance of heating equipment.

Oil and gas heated buildings commonly have boilers with a seasonal thermal efficiency of about 65 percent. High efficiency boilers with improved heat exchangers, radiant burners, higher firing chamber retention times, and induced draft can achieve a seasonal efficiency of almost 90 percent and operate more than 30 percent more efficiently than conventional boilers.

Other potential efficiency gains could be achieved from heat pump technology. Integrated heat pump systems can serve space heating, cooling and water heating needs. Actual energy savings will vary depending on local climate, the efficiency of the alternative system and the coefficient of performance of the heat pump.

The **cooling** load of a building can be reduced by measures to counteract internal and external heat gains such as window treatments and radiant barriers, improved wall insulation and air tightness, and more efficient lighting. However, improvements from these measures could be significantly offset over time given the uncertainty surrounding the commercial plug load growth.

Among the techniques to improve efficiency of cooling systems are the use of multi-stage energy efficient compressors[1], increased condenser/evaporator heat exchange surfaces, more energy efficient motors, variable frequency drives to modulate the chiller speed, ice or water-based thermal storage and the installation of heat pumps. Switching to efficient cooling systems could reduce seasonal cooling loads by 25 to 30 percent.

The major **ventilation** upgrade options relate to air flow control, motor efficiency improvements, and proper operation and maintenance. Energy use can be reduced through low-friction air distribution designs. In new and retrofit applications, a variable air volume system with variable frequency drive speed control could save up to 70 percent in energy use for air handling compared to a constant air volume system.

Energy use for food **refrigeration** in food retail stores can be reduced by about 20 percent through a number of energy efficient measures compared to normal practices. The measures

1 This refers to compressors with uneven capacity that can be cycled on and off in combinations that more closely match the cooling loads.

include the use of air barriers such as strip curtains and glass doors, the use of insulated covers outside of business hours, microprocessor control of unequal parallel compressors[1], multi-stage compressor systems and variable speed compressor control.

We have reviewed the impact of the above technologies, relative to those included in the Control Case over the projection period. While the discussion has focussed only on the office and retail sub-sectors, similar technologies exist for the remaining commercial sectors with the potential for corresponding energy savings. By the year 2010, we estimate that the adoption of the energy efficient technologies and measures discussed above (and including an allowance for improvements in other sub-sectors), could lead to a reduction in energy demand of as much as 35 percent, relative to Control Case levels.

11.7.1.3 Industrial Sector

In the Control Case we derived our projection of industrial demand based on our economic growth and energy price projections, and assuming the gradual implementation of certain currently available energy saving technologies and production processes over the projection period. More rapid and widespread penetration of such technologies and production processes could reduce industrial energy demand relative to the Control Case levels. Adoption of such measures may result in additional costs to industry, or may require specific policies in order to be realized.

In this discussion we provide estimates of the additional energy savings which would be possible if current technologies and production processes were to penetrate the industrial market more widely and at a faster rate than assumed in the Control Case. In developing these estimates, in consultation with industry experts, we found a wide range of views on the potential for further energy savings.

For the **pulp and paper** industry, we assumed in the Control Case a modest use of recycled fibre in newsprint production. Its use could be much higher, and with greater penetration of TMP and CTMP processes, cogeneration, energy efficient paper drying technologies and integrated production of pulp and paper, additional energy savings can be generated. These measures could lead to a reduction in energy use by the pulp and paper industry in the year 2010, of some 14 percent relative to the Control Case.

The **iron and steel** industry could further increase its use of ferrous scrap in mini-mills and basic oxygen furnaces, the share of mini-mills output in steel production, and the application of Lance Bubbling Equilibrium technology. Further penetration of these production technologies and processes relative to the Control Case could reduce the industry energy demand by an estimated 13 percent in the year 2010.

The Control Case assumed that new **aluminium** smelting capacity would adopt the same technology as currently installed at Becancour, Québec. However, smelting technologies being perfected at the present time use about 10 percent less energy than the one at Becancour. Installation of these technologies in new plants would reduce the industry's energy use. Additional energy savings can also be realized from the greater use of recycled aluminium. We estimate that a reduction of 7 percent in energy demand in 2010 from Control Case levels could be achieved if new smelting processes were used and a higher proportion of recyclable aluminium were utilized by the industry. We anticipate comparable reductions in energy intensity in the rest of the smelting and refining sector, because measures that reduce energy use in the production of aluminium can also be adopted elsewhere.

We estimate that the **cement** industry could achieve an additional reduction of some 13 percent in energy use by 2010, compared to our projections in the Control Case. This estimate is based on analysis which indicates considerable potential for further use of secondary cementing materials and waste derived fuels, and for production of cement at lower temperatures.

The potential for further reduction in energy demand in the **petroleum refining** industry is comparatively limited according to the industry experts. However, energy savings of about 5 percent in 2010 relative to the Control Case, can be expected from an intensive application of advanced heat recovery technologies, effective energy management and greater automation.

The **chemical** sector could make greater use of heat recovery technologies, new efficient electric motors, boiler upgrades, cogeneration and advanced energy saving

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1 This measure refers to the application of microprocessor and pressure controls to multiple, unequal-sized compressors of refrigeration systems. It enables the efficient staging of total compressor capacity to match actual refrigeration demand.

equipment than we have assumed in the Control Case. If such measures were to be implemented, energy demand for this industry in 2010 would be about 8 percent lower than in the Control Case.

The "**other manufacturing**" subsector is comprised of a large number of relatively small industrial plants engaged in the manufacturing of diverse products. In most cases energy consumption per unit of output is low. Although energy savings are realized in the Control Case, additional savings are possible from more extensive use of highly efficient electric motors, advanced heat recovery equipment, energy control and management methods, automation and the latest electro-technologies.

In both the **forestry** and **construction** sectors a reduction in energy demand of about 5 percent in 2010 relative to the Control Case is possible from more extensive application of energy efficient equipment and effective energy management.

The projected increase in energy intensity in the **mining** sector in the Control Case is mainly due to the energy requirements for bitumen production. Excluding energy use for bitumen production, the further application of energy saving measures such as the use of advanced heat recovery equipment, efficient electric motors and efficient equipment and production methods, could reduce the sector's energy demand by about 7 percent in 2010, relative to the Control Case.

Overall, we estimate that the implementation of the above measures could result in total industrial energy demand in the year 2010 some 12 percent below Control Case levels.

11.7.1.4 Transportation Sector

In this discussion we focus on road energy use, which accounts for approximately 80 percent of the transportation sector's energy use and emissions. In the Control Case we specified a number of measures which we assumed would be implemented over the projection period to improve fuel efficiencies. All of these measures reflected currently available, tested technologies, which are cost effective based on our projected price tracks. However, increased penetration of existing technologies along with introduction of additional technologies could further reduce energy demand in the transportation sector relative to our Control Case levels.

As for the other sectors, adoption of these measures may result in additional costs to users, or require specific policies to overcome cost or other impediments to their full penetration.

For cars, relative to the Control Case where we assume that 5 speed automatic and 6 speed manual transmission would be limited to luxury and performance cars, we assume that this technology could gradually replace all overdrive transmission. Continuously variable transmission, rather than being limited to expensive small cars, could become a standard feature on subcompacts. While we assumed only partial material substitution through use of high strength steel and plastics in the Control Case, full material substitution through high strength steel, plastics, and more expensive substitutes such as aluminium and graphite-fibre reinforced plastic are possible. A reduction in the drag coefficient to 0.28 (relative to about 0.35 in the Control Case) would further improve fuel efficiency, without a major loss of usable volume and comfort.

With respect to improvements to tires, lubricants and accessories, a more rapid switch to advanced synthetic lubricants than that assumed in the Control Case, adoption of low profile radials as a standard feature, and gradual penetration of tires using plastic compounds, would accelerate and increase fuel efficiency improvements relative to the Control Case.

Several additional gains with respect to engine upgrades could be contemplated. In addition to those measures in the Control Case (continued internal friction reduction; increased penetration of 4 valve cylinder technology; throttle body fuel injection and small penetration of multipoint fuel injection; full implementation of knock limiters and of deceleration fuel shut-off technologies; electronic transmission control as a standard feature and increased popularity of driving aids such as fuel consumption and shift indicators) high level penetration of 4 valve cylinder technology, gradual penetration of intake valve control technology, full penetration of multi-point fuel injection, driving aids as standard features, and some penetration of stop/start systems would accelerate and further improve car fuel efficiencies.

All of these measures could improve new car fuel efficiency over 1989-2010 by approximately an additional 25 percent, relative to the Control Case.[1]

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1 We arrived at the 25 percent estimate by examining the impact of each technology in the Control Case, and its contribution to fuel efficiency improvement, and then reviewing each of the additional measures listed above and assessing their incremental impact relative to the Control Case.

For trucks, additional efficiency gains are more restricted. In the Control Case we assumed for light trucks with respect to body/ drivetrain technologies that all trucks would have 4 speed automatic or 5 speed manual overdrive transmissions; continuously variable transmission would have limited application in subcompact trucks; there would be partial material substitution; there would be some reduction in the drag coefficient; a gradual switch to advanced synthetic lubricants; limited penetration of LT-metric and injection moulded tires; and some improved accessories. Additional improvements could include a replacement of the old generation overdrive with 5 speed automatic and 6 speed overdrive transmission; continuously variable transmission on all subcompact trucks; full material substitution through use of high strength steel, plastics and more expensive substitutes such as aluminium and graphite-fibre reinforced plastic; increased drag reduction relative to the Control Case; a more rapid switch to advanced synthetic lubricants; LT-metric and injection moulded tires as standard features; and further accessory improvements such as electric power steering.

In the Control Case we assumed that the following engine upgrades would occur for light trucks: continued internal friction reduction; an increasing share of trucks with overhead cam engines; fuel injection in all new light trucks, and multipoint systems in 50 percent; a 70 percent penetration of transmission controls. Further gains could be achieved by: introducing overhead cam engines in 75 percent of light trucks, and 4 valve cylinder technology in 30 percent; multipoint fuel injection in all new light trucks, and full penetration of transmission controls.

For light trucks these additional measures could improve new truck fuel efficiency over the 1989-2010 period by about an additional 15 percent (that is roughly a 30 percent improvement in fuel efficiency over the period, relative to about 15 percent in the Control Case).

For medium and extra-heavy trucks further gains are much more restricted, and increased penetration of measures assumed in the Control Case would likely lead to further fuel efficiency gains of only about 5 percent, relative to the Control Case, by 2010.

11.7.2 Emissions Reduction Measures Related to Electricity Supply

The Control Case assumes that utilities will be successful in achieving gaseous emission levels of SO_2 and NO_x over the study period which are at or below present provincial and federal limits. Emissions from utility electricity supply of NO_x grow only moderately, and of SO_2 decline over the study period in the Control Case, despite growth in fossil fuel-fired generation. However, as there are currently no provincial or federal CO_2 emission limits nor technology in place to significantly mitigate such emissions, the Control Case shows greater growth in emissions of CO_2 from thermal generation over the study period.

Over and above the mitigative measures included in the Control Case, utilities could take a number of additional measures to reduce atmospheric emissions and enhance air quality over the study period. They include:

- increased conservation of energy through demand management techniques; although the Control Case does reflect some demand management, further reductions in electricity demand could be achieved as more advanced techniques are used to increase end use efficiencies;
- increased coordination of complementary hydro/thermal systems (for example, by coordinating operations with the hydro system of British Columbia, Alberta may be able to decrease its thermal generation while still meeting its in-province needs);
- displacement of thermal generation by other alternative supplies that do not contribute to atmospheric emissions, including nuclear, hydro, solar, wind, and tidal power. For example, based on our consultations, the Control Case assumes new coal-fired capacity for New Brunswick, whereas the generation expansion program could be based on new nuclear capacity. However, some of these alternate generation forms have other environmental impacts beyond those addressed in this study.

The extent to which such measures will actually be implemented will depend on their practicality and economic viability.

As well as these measures, there are several advanced technologies currently being examined by utilities based on new combustion processes which show promise of significantly reducing gaseous emissions. Integrated gasification combined cycle (IGCC) appears to be the leader in the current "clean-coal" technologies. IGCC genera-

tion could substantially reduce current emission levels of SO_2 and NO_x and is seriously being considered in the future expansion plans of several utilities in Canada (such as in Alberta). However, we have not included such facilities is our Control Case because the expected long lead times required between their development and full commercial operation would preclude any significant implementation within the study period. Non-utility generation in the form of cogeneration produces useful heat (usually in the form of steam) as well as electricity, enhancing overall fuel efficiency in the process, and could become a more significant factor over the study period. Emerging technologies such as fuel cells (a device in which hydrogen reacts electrochemically with oxygen to generate electricity) may also help reduce acid and greenhouse gas emissions in the future, but their contribution is likely to be modest over the study period.

11.7.3 Emissions Reduction Measures Related to Natural Gas, Conventional Crude Oil, Bitumen and Coal Production

The emissions arising from natural gas, conventional crude oil, bitumen and coal production are generally small relative to those arising from primary energy demand in Canada. However, there are reduction measures which could be adopted, depending on their economic viability.

The reduction of emissions of CO_2 from natural gas production and synthetic crude production from mined bitumen will depend on future improvements which are made to processing technologies to enhance combustion efficiencies and the extent to which raw CO_2, which would otherwise be released into the atmosphere, is recovered and reinjected into subsurface reservoirs, perhaps for miscible flood purposes. There are currently four such schemes operating in Alberta which capture CO_2 from natural gas plant emissions for use in miscible flood projects.

The reduction of emissions of NO_x from natural gas production and synthetic crude production from mined bitumen will depend on future improvements which are made to processing technologies to enhance combustion efficiencies, as well as on the extent to which there is switching to fuels which emit lower levels of NO_x.

A reduction of methane emissions from coal mining could be accomplished with increased implementation and efficiency of drainage and ventilation systems, assuming the CH_4 is captured for fuel or other use rather than being emitted to the atmosphere.

Upstream SO_2 emissions could be reduced with improved sulphur recovery from natural gas and synthetic crude oil plants (relative to the current recovery rates of about 98 and 88 percent, respectively). Additionally, SO_2 emissions could be lowered by reducing the level of sour solution gas flaring. The implementation of existing SO_2 recovery technology at all existing natural gas and bitumen processing facilities could reduce SO_2 emissions to minimal levels. However, this is not currently economically viable in many circumstances. Technological change and regulatory policies will largely determine the extent to which these reduction measures are implemented over the projection period.

Emissions reduction measures implemented on the demand side involving increased use of natural gas will likely have the effect of increasing production-related emissions.

11.8 Concluding Comments

Based on our domestic energy supply and consumption outlook we have developed projections of gaseous emissions. We have made allowance in our projections for environmental policies in place as of the end of 1990 and for ongoing improvement in energy efficiency. Notwithstanding this, emissions of *carbon dioxide* are projected to increase from 533 000 kilotonnes in 1989 to 675 000 kilotonnes by 2010, an annual average increase of 1.1 percent. *Nitrogen oxides* emissions also increase, from 1970 kilotonnes in 1989 to 2050 kilotonnes by 2010, an annual average increase of 0.2 percent. However, emissions of *Volatile Organic Compounds* are expected to decrease from 840 kilotonnes in 1989 to 690 kilotonnes by 2010, an annual average decrease of 0.9 percent. *Sulphur dioxide* emissions are also expected to decrease, from 1355 kilotonnes in 1989 to 1140 kilotonnes by 2010, an annual average decrease of 0.8 percent.

These projected emissions include only energy-related emissions; they do not encompass all energy-related emissions. For example, we have not accounted for methane emissions, nor for all energy-related emissions of VOC.

The emissions projected are subject to uncertainty related both to the projected levels of energy supply and demand and to the emissions factors used.

These emissions could be further mitigated by introducing new consumption and production technologies which have not been included in the Control Case because they are generally not yet commercially viable. Over a time horizon as long as 20 years, a portion of this potential for further emissions reductions could be realized through innovations in technology and in manufacturing processes which lead to the economic viability of certain emissions reduction measures or by the introduction of specific policy measures. We have described many of the available emissions reductions measures and provided an indication as to their possible impact on gaseous emissions.

Finally, while we have endeavoured to take environmental concerns into account in the analytical work conducted for this report, the nature of this issue is such that there could be significant changes in our economic structure over the period of this study which extend well beyond the analysis we have presented.

Chapter 12

Conclusions

Canada's energy future will be determined by a combination of domestic and international factors influencing the rate and character of economic growth, energy price development and the ways in which we produce and consume energy. We have cast our analysis in the context of the existing framework of institutional practices and public policies, the most important feature of which is that market forces will largely determine energy prices, supplies and demands. We have assumed that this framework will continue over the study period.

In the Control Case, we assume long-term economic growth of about 2.3 percent per year. The economy could perform above or below this estimate, which would cause our energy demand projections to vary accordingly as noted below.

Energy pricing is fundamental to any supply and demand outlook, and oil prices have an important influence on energy pricing in general. We project a sustainable range of oil prices over the longer term, although we recognize that prices may temporarily fall outside the range. Our outlook is for sustainable *oil prices* ranging from \$18 to \$22 per barrel in 1991, with the range growing to \$20 to \$35 in 2010 (all in 1990 U.S. dollars). This range reflects both political and economic uncertainties associated with projecting long-term oil prices. For analytical purposes, we have presented a Control Case roughly in the middle of the range, growing from \$20 in 1991 to \$27 by 2010.

Natural gas pricing is determined in the North American market, and our assessment of future prices is influenced by assumptions about the size and costs of natural gas resources and the growth in natural gas demand. A plausible range of natural gas prices results from our various scenarios, but we do project substantial real growth in natural gas prices over the study period. Our Control Case Alberta natural gas fieldgate price increases from \$1.40 per gigajoule in 1992 to \$4.20 in 2012, and our sensitivity cases produce a range of \$3.50 to \$4.65 by 2012 (all in 1990 Canadian dollars).

We have attempted to reflect a measure of technological improvement in our analysis but recognize that some will suggest that we have not yet adequately accounted for the extent to which advances in technology may mitigate increases in costs and thereby prices over the longer term. We also anticipate that the ongoing supply surplus in Western Canada will continue to place downward pressure on natural gas prices in the short term, perhaps to a greater extent than accounted for in our results. However, our projection of both world crude oil prices and of North American natural gas prices over the longer term tend to be at the lower end of the range of published projections.

Electricity prices are not market determined, but are largely regulated on a cost-of-service basis. In the short term our price outlook is guided by the announced intentions of the utilities. Based on our consultations with utilities, we think it reasonable to assume that over the long term additional supply can generally be produced at a rolled-in cost which will remain stable in real terms.

Our expectations are for low **energy demand** growth for Canada, with end use demand growing from 7600 petajoules in 1989 to 9800 petajoules in 2010 in the Control Case, an increase averaging 1.2 percent per year. These projections are predicated on modest economic growth, ongoing energy efficiency improvements associated with technological change, environment-related measures considered viable given our price outlook, and demand management programs.

We recognize that demand could be somewhat greater than we have projected, for example if economic growth were greater or efficiency gains less than in our analysis. Energy demand growth could also be less than in our Control Case, for example due to more aggressive environmental protection or economic growth lower than we have assumed, especially if growth were more heavily weighted toward less energy-intensive activity. It is plausible that demand may be from 10 percent below our Control Case to 15 percent above by 2010.

End use fuel shares are expected to change very moderately over the projection period. Although the gas share increases slightly in the period to 2000, by 2010 the shares of electricity (22 percent) and coal (6 percent) are each about 2 percentage points higher than in 1990, and those of oil (37 percent) and gas (25 percent) are lower than in 1990.

Our price projections, demand profiles and assumptions regarding the size and cost of the resource have interesting implications for **energy supply and international trade**.

Our projections of the expansion of **electricity generating capacity** are driven by our analysis of the prospects for electricity demand growth, given our outlook on the rate and characteristics of economic growth, on electricity prices, on the penetration of new technologies, and on the effect of demand management programs and incentive pricing arrangements. We conclude that, on average over the study period, the rate of growth in electrical energy demand will be at a rather modest 1.5 percent per year.

Based on commitments already made, and on our assessment of utility plans and of U.S. markets, we see **firm exports of electricity** rising from the 1990 level of 18 terawatt hours to about 47 terawatt hours in 2010. Over the past several years, Canada's net electricity exports have fallen from the levels achieved in the mid-1980s because of Quebec's low water levels and nuclear reactor shutdowns in Ontario. Our analysis suggests that the pattern of interruptible trade will revert to the pattern of the mid-1980s, as increasing generating capacity and a return to more normal levels of precipitation result in a decline of imports to Canada and an increase in interruptible exports. Over the long run, export trade is likely to consist increasingly of firm exports.

Our review leads us to conclude that, notwithstanding our projection of relatively low load growth rates and growth in generation alternatives such as natural gas turbines and despite demand management programs, we will need to rely on substantial expansion of conventional sources of supply such as hydro, coal and nuclear capacity to meet the bulk of Canadian electricity demand over the study period. Some provincial utilities expect higher load growth rates than in our projections, and have committed to expansion plans accordingly.

We observe growing interest in mutually beneficial interprovincial electricity trade. This potential, combined with the possible contribution of independent power producers, widens the range of supply options which utilities can pursue.

On the electricity supply side, identification of needed capacity resources for only five to six years into the future has become a more common practice because of the major uncertainties associated with the commitment of facilities requiring long lead times. This has two kinds of risks: first that utilities will not achieve the lowest long-run incremental cost of generation, and second that additional capacity may not be available when needed to maintain adequate reserve margins.

The generation plans of several provinces have undergone or are now undergoing environmental scrutiny including public hearings held by provincial agencies. In other instances, the process of environmental review remains to be finalized. Environmental considerations associated with new electricity supplies (including a range of socio-economic factors as well as any physical impacts of development on the environment) can have an important impact not only on the timing of these developments but indeed on whether they will be developed at all.

For **natural gas** we project substantial growth in demand, especially in the U.S. electrical generation market, until around 2000. From 2000 to 2010 natural gas demand growth moderates in the Control Case because natural gas prices exceed heavy fuel oil prices, causing substitution of heavy fuel oil for natural gas. Canadian natural gas demand in the Control Case increases from 2.6 EJ in 1989 to 3.2 EJ in 2010, an average annual increase of 1 percent. Taking into account comparative gas supply and transportation costs between Canada and the U.S. and the growing size of the U.S. market, **natural gas net exports** grow from 1.4 EJ in 1989 to a peak of 2.4 EJ in 2007, and then recede to about 2.2 EJ by 2010 as supply from Western Canada begins to decline and frontier supply sources become competitive. Mackenzie Delta production in the Control Case commences in 2004 and Alaskan supply to the Lower-48 states commences very late in the study period. Imports to Ontario grow from about 25 petajoules in 1991 to almost 0.3 EJ in 2010. Total Canadian production is projected to increase from 4.0 EJ in 1989 to 5.6 EJ in 2007, and to moderate to 5.4 EJ in 2010.

As productive capacity from established reserves declines over the projection period, it will increas-

ingly become necessary to rely on productive capacity from reserves additions in the WCSB, along with productive capacity from the frontier regions, to meet the increasing levels of domestic and export demand. A total of 72 exajoules of natural gas from the WCSB, or an average of 3.4 exajoules per year, is projected to be added over the period 1990 to 2010 in the Control Case.

These supply, demand, trade, and price results are sensitive to assumptions about uncertain variables, especially oil prices and natural gas resource and supply costs. Low oil prices cause natural gas prices to be lower than in the Control Case. Therefore, in the low oil price case natural gas loses market share to oil earlier in time than in the Control Case and Canadian exports are lower. Higher oil prices allow higher natural gas prices, increased gas consumption and higher Canadian exports relative to those in the Control Case. With regard to Northern projects, low oil prices cause Mackenzie Delta gas to be delayed to about 2010 and Alaska gas to beyond 2010, while high oil prices allow the development of Mackenzie Delta gas around 2002 and Alaska gas somewhat earlier than in the Control Case. Canada's export potential and overall natural gas production is most sensitive to what one assumes about the size and associated costs of the Canadian natural gas resource relative to that of the U.S. The impacts of a range of estimates of recoverable resources and related supply costs for Canada and the U.S. were assessed in sensitivity cases. By 2012, our results indicate that net Canadian exports could be as low as some 1.3 EJ per year or as high as about 4 EJ per year with low and high estimates of the WCSB natural gas resource, respectively. The analytical framework we are using is such that markets are presumed to adjust smoothly to whatever assumptions are used about the resource and oil prices. Of course, prices can fluctuate substantially over time as markets adjust to changing circumstances.

Our results indicate lower natural gas prices, a larger gas market and higher net exports than shown in the 1988 Report. There are several reasons for this. Between 1988 and now, the long-term demand outlook for the U.S. market has increased because of environmental considerations, increased expected reliance on natural gas for electricity generation and increased optimism about indigenous gas supply. We have used a more generous estimate of U.S. resource potential and have reduced U.S. supply costs somewhat relative to those used in the 1988 Report. For Canada, we have used a higher estimate of resource potential in the WCSB in the Control Case and reduced our estimates of input costs, such as for drilling, both of which have the effect of reducing supply costs and lowering prices as compared to the 1988 Report. We have also attempted to reflect a more competitive energy market environment in our natural gas transportation and distribution charges, which generally has the effect of reducing these costs relative to those in the 1988 Report.

Our results suggest the importance of caution in gauging the future development of the natural gas market. There are large uncertainties about factors which can have important impacts on results, and the analytical framework itself has limitations in portraying how the market functions or reacts to changed circumstances. Our main purpose in conveying these results is to indicate broad, plausible directions of change, to the extent our information and methods allow, and to illustrate the sensitivity of results to alternative assumptions about key uncertain factors.

We have focussed our **oil supply** analysis on the Control Case crude oil price path and conducted high oil price and low oil price sensitivity tests to assess the impact of alternative crude oil price projections on our supply outlook. In addition to crude oil price, there are a number of other uncertain parameters, including the size of the resource and the pace of technological change, which could substantially influence the outlook for crude oil supply. Overall, our Control Case outlook suggests that Canada's crude oil and equivalent supply will remain relatively stable over the projection period, declining initially and then increasing to a level 16 percent higher in 2010 than in 1990. While the total supply of crude oil and equivalent is projected to change only modestly, the average quality of the crude oil and the regional distribution of supply changes considerably. Over the projection period heavy crude oil comprises an increasing proportion of the total supply and the importance of frontier supply increases, whereas supply of light crude oil from Western Canada becomes relatively less significant. Our oil price sensitivity tests indicate that the outlook for frontier, synthetic crude oil, and bitumen supply is particularly sensitive to the crude oil price projection. Many new Canadian supply sources are relatively high cost by world standards and will require real growth in prices or technological changes which reduce costs in order to become viable over the projection period.

Our Control Case crude oil and equivalent supply projection is very similar to the low case of our 1988 Report during the early portion of the projection period, but thereafter moves gradually toward the high case of that report. As in the 1988 Report, the contribution of heavy crude oil supply, particularly bitumen, and frontier supply increases and conventional light crude oil supply from the Western Canada Sedimentary Basin declines over the projection period. This has certain implications for the crude oil transportation system and refinery configuration in Canada. Light crude oil shipments from Western Canada to Montreal via the Sarnia-Montreal segment of the Interprovincial Pipe Line system have recently ceased. As light crude oil supply from the Western Canada Sedimentary Basin continues to decline, it will be necessary for Ontario refiners to examine their supply options, one of which would be to reverse the Sarnia-Montreal line to allow imported light crude oil to be shipped to Sarnia via Portland, Maine. We anticipate that over most of the projection period the growth in domestic demand for petroleum products can be met by increased utilization of existing domestic refinery capacity, together with some modest debottlenecking of refineries in conjunction with investments which will be necessary to meet more stringent environmental standards.

In our Control Case projection supply exceeds domestic crude oil demand throughout the projection period and Canada therefore remains a net exporter of crude oil and equivalent. We anticipate, however, increasing volumes of light crude oil imports to satisfy refinery feedstock requirements in the Maritimes, Quebec and Ontario and exports, primarily to the U.S., of large volumes of heavy crude oil produced in Western Canada and light crude oil produced from the East Coast offshore.

Domestic demand for **natural gas liquids** is expected to increase despite reductions in the demand for NGL for use in miscible flood projects. Domestic demand for ethane is projected to increase as a result of the construction of a new ethylene plant. Propane demand is projected to rise in all sectors, with the most significant increases being in the transportation and petrochemical sectors. Completion of an MTBE plant currently under construction leads to an increase in butanes demand.

We anticipate that liquids yields will remain relatively constant but this depends upon a number of factors, including the composition of future natural gas discoveries; as a result there is uncertainty in this projection. NGL supply potential is expected to increase over the period as natural gas production increases in response to rising domestic and export demand. Overall, our projections of NGL supply are up significantly from the high case projections in our 1988 Report because of higher projections of natural gas production and of liquids yields. To the extent that natural gas production were higher or lower than projected in the Control Case, there would be a commensurate increase or decrease in the potential NGL supply. Our analysis indicates that for each of ethane, propane and butanes there will be a substantial excess of potential supply over domestic demand during the projection period.

Our projections in the Control Case show considerable growth in domestic demand for **coal** over the study period. In Ontario and Quebec markets, domestic supply continues to face stiff competition from U.S. coals, and Canadian producers are not expected to increase their market shares. Growth in electricity generation markets in the West and in the Atlantic region are projected to result in increased demand for Canadian coals.

With regard to world coal trade we see continued growth, particularly for thermal coals. Canada is at a competitive disadvantage in some markets, mainly because of high transportation costs incurred in moving coals long distances by rail to tidewater and the emergence of new low cost suppliers on the world scene. We think it reasonable to expect that we will be able to expand our exports of thermal coal, but that overall we will lose market share. Expansion of thermal coal exports may depend on the extent to which buyers wish to maintain diverse supply sources. With regard to metallurgical coal exports we have assumed that we will be able to maintain our existing level of exports.

Based on our domestic energy supply and consumption outlook we have developed projections of **gaseous emissions**. We have made allowance in our projections for environmental policies in place as of the end of 1990 and for ongoing improvement in energy efficiency. Notwithstanding this, emissions of *carbon dioxide* are projected to increase from 533 000 kilotonnes in 1989 to 675 000 kilotonnes by 2010, an annual average increase of 1.1 percent. *Nitrogen oxides* emissions also increase, from 1970 kilotonnes in 1989 to 2050 kilotonnes by 2010, an annual average increase of 0.2 percent. However, emissions of *Volatile*

Organic Compounds decline from 840 kilotonnes in 1989 to 690 kilotonnes by 2010, an annual average decrease of 0.9 percent. *Sulphur dioxide* emissions also decline, from 1355 kilotonnes in 1989 to 1140 kilotonnes by 2010, an annual average decrease of 0.8 percent.

These projected emissions include only energy-related emissions; they do not encompass all energy-related emissions. The emissions projected are subject to uncertainty related both to the projected levels of energy supply and demand and to the emissions factors used.

These emissions could be further mitigated by introducing new consumption and production technologies which have not been included in the Control Case because they are generally not yet commercially viable. Over a time horizon as long as 20 years, a portion of this potential for further emissions reductions could be realized through innovations in technology and in manufacturing processes which lead to the economic viability of certain emissions reduction measures or by the introduction of specific policy measures. We have described many of the available emissions reduction measures and provided an indication as to their possible impact on gaseous emissions. While we have endeavoured to take environmental concerns into account in the analytical work conducted for this report, the nature of this issue is such that there could be significant changes in our economic structure over the period of this study which extend well beyond the analysis we have presented.

Finally, we emphasize that there is considerable uncertainty inherent in any long-term projection of energy supply and demand and that we do not view our Control Case as a most likely projection. It is a projection around which we have conducted certain sensitivity tests for key variables having a credible range of values. Our main interest in the sensitivity tests is to illustrate a plausible range of results and to better understand the forces which determine the range. Users of our results can select the area of the projection they prefer based on their views of the range of assumptions we have tested.

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Appendix 11

Appendix 1 Abbreviations, Conversion Factors, Glossary

Table A1-1
Abbreviation of Names, Terms and Units

(i) Names

Act *the National Energy Board Act*

AGA American Gas Association

ALCAN Aluminium Company of Canada Ltd.

ANG Alberta Natural Gas Company Ltd.

ANGTS Alaska Natural Gas Transportation System

A & S Alberta and Southern Gas Company Limited

BC Gas BC Gas Inc.

BC HYDRO British Columbia Hydro and Power Authority

BCPC British Columbia Petroleum Corporation

(the) Board or NEB (the) National Energy Board

BPA Bonneville Power Administration (U.S. Federal Agency)

CANMET Canada Centre for Mineral and Energy Technology

CEC California Energy Commission

CERI Canadian Energy Research Institute

COGLA Canada Oil and Gas Lands Administration

Consumers Gas The Consumers' Gas Company Ltd.

CPA Canadian Petroleum Association

Cyanamid Cyanamid Canada Pipeline Inc.

DFI Decision Focus Incorporated

DOE Department of Energy (U.S.)

DOI Department of the Interior (U.S.)

EIA Energy Information Administration (U.S.)

El Paso El Paso Natural Gas Company

EMR Energy, Mines and Resources

EPA Environmental Protection Agency (U.S.)

ERCB Alberta Energy Resources Conservation Board

Esso Esso Resources Canada Limited

FERC Federal Energy Regulatory Commission (U.S.)

Foothills Foothills Pipe Lines (Yukon) Ltd.

GATT General Agreement on Tariffs and Trade

GEA Geological Exploration Associates

GMi Gaz Métropolitain, inc.

GRI Gas Research Institute

GSC Geological Survey of Canada

Gulf Gulf Canada Resources Limited

ICG (MAN) ICG Utilities (Manitoba) Ltd.

ICG (ONT) ICG Utilities (Ontario) Ltd.

Inland Inland Natural Gas Co. Ltd.

IPL or Interprovincial Interprovincial Pipe Line Company, A Division of Interhome Energy Inc.

LOOP Louisiana Offshore Oil Port

Manitoba PUB Public Utilities Board of Manitoba

MECL Maritime Electric Co. Ltd. (Prince Edward Island)

MichCon Michigan Consolidated Gas Company

Mobil Mobil Oil Canada, Ltd.

NB Power New Brunswick Electric Power Commission

NCO North Canadian Oils Limited

NEPOOL New England Power Pool (U.S.)

NERC North American Electric Reliability Council

NGPA Natural Gas Policy Act of 1978 (U.S.)

NLH Newfoundland and Labrador Hydro

NOVA NOVA Corporation of Alberta

Northern Border Northern Border Pipeline Company

Northwest Northwest Pipeline Corporation

Northwest Alaskan Northwest Alaskan Pipeline Company

NP Newfoundland Power

NS Power Nova Scotia Power Corporation

NTPC Northwest Territories Power Corporation

NYPA New York Power Authority (U.S.)

October 1986 Report *Canadian Energy Supply and Demand 1985-2005*, Summary and Detailed Reports, National Energy Board, October, 1986

OEB Ontario Energy Board

OECD Organization for Economic Cooperation and Development

OPEC Organization of Petroleum Exporting Countries

Pan-Alberta Pan-Alberta Gas Limited

PCEC Pacific Coast Energy Corporation

PGC Potential Gas Committee (U.S.)

PGT Pacific Gas Transmission Company

PG & E Pacific Gas and Electric Company

ProGas ProGas Limited

Régie Régie du gaz naturel (Quebec)

September 1988 Report *Canadian Energy Supply and Demand 1987-2005*, Summary and detailed reports, National Energy Board, September, 1988

Shell Shell Canada Limited

SIMPLOT Simplot Canada Limited

So Cal Southern California Gas Company

SPC Saskatchewan Power Corporation

TCPL or TransCanada TransCanada PipeLines Limited

TOPGAS TOPGAS Holdings Limited and TOPGAS Two Inc.

TQM Gazoduc Trans Québec & Maritimes Inc.

TRANSALTA TransAlta Utilities Corporation (Alberta)

TransGas TransGas Limited

Trans Mountain Trans Mountain Pipe Line Company Ltd.

Union Union Gas Limited

United United Gas Pipe Line Company

U.S. United States

USSR Union of Soviet Socialist Republics

Viking Viking Gas Transmission Company (Successor to Midwestern Gas Transmission Company)

WGML Western Gas Marketing Limited

Westcoast Westcoast Energy Inc.

WEFA Wharton Econometric Forecasting Associates

WKPL West Kootenay Power Ltd.

YEC Yukon Energy Corporation

(ii) Terms

ACQ Annual Contract Quantity

AMP (Alberta) Average Market Price

CD Contract Demand

CH_4 Methane

CMP Competitive Marketing Program

CO_2 Carbon Dioxide

CPE Centrally Planned Economies

CTMP Chemi-Thermo-Mechanical Pulping

EDM Energy Demand Model

EOR Enhanced Oil Recovery

FFV Full fixed variable

FS Firm Service

FST Firm Service Tendered

GDP Gross Domestic Product

GNE Gross National Expenditure

GNP Gross National Product

HFO Heavy fuel oil

IPP Independent Power Producers

IS Interruptible Transportation Service

IS-1 Tier One Interruptible Transportation Service

IS-2 Tier Two Interruptible Transportation Service

LDC Local Distribution Company

LFO Light fuel oil

LNG Liquefied Natural Gas

LPG Liquefied Petroleum Gases

MFV Modified fixed variable

NARG North American Regional Gas Model

NGL Natural Gas Liquids

NGV Natural Gas for Vehicles

NO Nitric oxide

NO_2 Nitrogen dioxide

N_2O Nitrous oxide

NO_x Nitrogen oxides

NUG Non-Utility Generation of electricity

OD Operating Demand

PNW Pacific Northwest

RDP Real Domestic Product

R/P Reserves to production ratio

SGR System Gas Resale

SNG Synthetic Natural Gas

SO_2 Sulphur Dioxide

STS Storage Transportation Service

TMP Thermo-Mechanical Pulping

VOC Volatile Organic Compounds

WCSB Western Canada Sedimentary Basin

WTI West Texas Intermediate

(iii) Units

Prefix	Multiple	Symbol
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

°API = Degrees gravity on American Petroleum Institute scale (See Glossary)
Btu = British thermal unit
psia = Pounds per square inch absolute
ppmv = parts per million by volume

Mcf = Thousand cubic feet
Bcf = Billion cubic feet
Tcf = Trillion cubic feet

kt = kilotonnes
Mt = megatonnes

bbl = barrels
MMbd = millions of barrels per day

$C = Canadian dollars
$US = United States dollars

GJ	gigajoule	=	10^9Joules(J)
TJ	terajoule	=	10^{12}J
PJ	petajoule	=	10^{15}J
EJ	exajoule	=	10^{18}J

kW	kilowatt	=	10^3Watts
kW.h	kilowatt hour	=	10^3W.h
MW	megawatt	=	10^3kW
MW.h	megawatt hour	=	10^3kW.h
GW	gigawatt	=	10^6kW
GW.h	gigawatt hour	=	10^6kW.h
TW	terawatt	=	10^9kW
TW.h	terawatt hour	=	10^9kW.h

Table A1-2
Conversion Factors

(i) *Metric to Imperial*

Metric Units	Imperial Equivalent Units
1 cubic metre of oil	
(15°C and 922 kg/m^3)	= 6.292 26 barrels (60°F and 22°API) for conventional heavy crude oil
(15°C and 855 kg/m^3)	= 6.292 58 barrels (60°F and 34°API) for conventional light crude oil
(15°C and 739 kg/m^3)	= 6.294 03 barrels (equilibrium pressure, 60°F and 60°API) for pentanes plus
1 cubic metre of natural gas (101.325 kilopascals and 15°C)	= 35.301 01 cubic feet (14.73 psia and 60°F)
1 cubic metre of ethane (liquid) (equilibrium pressure and 15°C)	= 6.330 barrels of ethane (equilibrium pressure and 60°F)
	= 9.930 thousand cubic feet of ethane gas (14.73 psia and 60°F)
1 cubic metre of propane (liquid) (equilibrium pressure and 15°C)	= 6.300 barrels of propane (equilibrium pressure and 60°F)
1 cubic metre of butanes (liquid) (equilibrium pressure and 15°C)	= 6.297 barrels of butanes (equilibrium pressure and 60°F)
1 tonne	= 1.102 311 short tons
1 kilojoule	= 0.948 213 3 British thermal units (Btu)
1 gigajoule (GJ)	= approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf
1 petajoule (PJ)	= approximately 0.95 billion cubic feet of natural gas, or 165 000 barrels of oil, or 0.28 terawatt hours of electricity

(ii). Gross Energy Content Factors

Natural Gas (at 15°C, 101.325 kPa and free of water vapour.)

B.C.	- domestic	39.10 MJ/m^3
	- Huntingdon	39.10 MJ/m^3
	- Kingsgate	37.65 MJ/m^3
	- Grassy Point	38.20 MJ/m^3
Alberta	- domestic	38.80 MJ/m^3
	- Cardston	37.65 MJ/m^3
	- Aden	36.06 MJ/m^3
East of Alberta		37.65 MJ/m^3

Ethane (liquid)		18.36 GJ/m^3
Propane (liquid)		25.53 GJ/m^3
Butanes (liquid)		28.62 GJ/m^3
Crude Oil	- Light	38.51 GJ/m^3
	- Heavy	40.90 GJ/m^3
	- Pentanes Plus	35.17 GJ/m^3
Coal	- Anthracite	27.70 GJ/tonne
	- Bituminous	27.60 GJ/tonne
	- Subbituminous	18.80 GJ/tonne
	- Lignite	14.40 GJ/tonne
	- Average domestic use	22.20 GJ/tonne
Petroleum Products	- Aviation Gasoline	33.52 GJ/m^3
	- Motor Gasoline	34.66 GJ/m^3
	- Petrochemical Feedstocks	35.17 GJ/m^3
	- Naphtha Specialties	35.17 GJ/m^3
	- Aviation Turbo	35.93 GJ/m^3
	- Kerosene	37.68 GJ/m^3
	- Diesel	38.68 GJ/m^3
	- Light Fuel Oil	38.68 GJ/m^3
	- Lubes and Greases	39.16 GJ/m^3
	- Heavy Fuel Oil	41.73 GJ/m^3
	- Still Gas	41.73 GJ/m^3
	- Asphalt	44.46 GJ/m^3
	- Petroleum Coke	42.38 GJ/m^3
	- Other Products	39.82 GJ/m^3

Electricity

Secondary		3.6 MJ/kW.h
Primary	- Hydro	3.6 MJ/kW.h
	- Nuclear	12.1 MJ/kW.h

Table A1-3
Glossary

Acid Rain *(Pluies acides)* Sulphuric, nitric, organic, or other acids that acidify rain water.

Adjusted Productive Capacity (gas) *(Capacité de production rajustée [gaz naturel])* The estimated productive capacity at any point in time, carrying forward for future use any productive capacity resulting from an earlier excess of productive capacity over production. (See also 'productive capacity')

American Petroleum Institute Scale *(Échelle de l'American Petroleum Institute)* Measures the relative density of crude oil and oil products; the higher the number, the lower the relative density.

$$°API = \left(\frac{141.5}{\text{specific gravity}}\right) - 131.5$$

Associated Gas *(Gaz associé)* Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir.

Backstop Cost (gas) *(Coût filet [gaz naturel])* The lesser of:
(i) the highest cost unit of gas likely to be produced at some future time, and
(ii) the cost of the most easily substitutable fuel.
The higher the estimated backstop cost, the higher the estimated user cost.

Backstop Supplies *(Service d'appoint)* A service whereby back-up gas is provided in the event that a customer's gas fails to be delivered to the distributor.

Base Load Capacity *(Capacité de production de la charge de base)* Electricity generating equipment which operates to supply the load over most hours of the year.

Basic Oxygen Furnace *(Convertisseur basique)* A process used in steel making. In this process molten raw iron, with added lime, is subjected to jets of pure oxygen. The oxygen burns out the carbon to produce steel.

Blended Heavy Oil *(Pétrole lourd mélangé)* Heavy crude oil to which light oil fractions have been added in order to reduce its viscosity to meet pipeline specifications.

Biomass *(Biomasse)* Organic material such as wood, crop waste, municipal solid waste and mill waste, processed for energy production.

Bitumen *(Bitume)* See 'Crude Bitumen'.

Blowdown *(Purge rapide)* The production of gas, either from the gas cap of an oil reservoir, normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.

Broker *(Courtier)* A gas broker is an entity other than an LDC that brings together buyers and sellers of gas and may or may not take title to the gas. Thus the broker acts as an agent or consultant.

Bundled Rate *(Taux regroupé)* A single charge that covers a number of services provided by a pipeline or distributor. Examples of such services are gas sales, transportation, storage and load-balancing.

Burner-tip or Retail Price (gas) *(Prix à la pointe du brûleur ou de détail [gaz naturel])* The city-gate price plus local distribution charges; the price paid by the end user.

Butanes *(Butanes)* In addition to its normal scientific meaning, a mixture mainly of butanes which ordinarily may contain some propane or pentanes plus.

Buy/Sell *(Achat-vente)* In this arrangement, the end-user purchases its own supply of gas and arranges for transportation, generally to the distributor's delivery point. The distributor purchases the gas and commingles it with the balance of its supplies, and then sells gas to the end user as a sales customer under the appropriate rate schedule.

Bypass *(Dérivation)* Bypass involves the total avoidance of the LDC's system for the transportation of gas.

Capacity (electricity) *(Capacité [électricité])* The maximum amount of power which a machine, apparatus or appliance can generate, utilize or transfer, expressed in kilowatts or some multiple thereof.

Capacity Available (electricity) *(Capacité disponible [électricité])* The sum of the installed capacity in a system plus firm purchases.

Capacity Brokering *(Courtage de la capacité)* The selling or renting by a shipper of its contracted pipeline capacity to others.

Carbonate *(Carbonate)* A sedimentary rock primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite).

Carbon Dioxide Flooding *(Injection de dioxyde de carbone)* An improved recovery process in which carbon dioxide is injected into an oil reservoir to increase recovery.

Chemical Flooding *(Injection de produits chimiques)* An improved recovery process in which water, with added chemicals, is injected into an oil reservoir to increase recovery.

Chemi-Thermo-Mechanical Pulping *(Technique chimio-thermo-mécanique de la production de pâtes)* Same as Thermo-Mechanical Pulping but with chemicals being added to the chips to further refine the pulp by removing the lignin.

City-gate or Wholesale Price (gas) *(Prix à l'entrée de la ville ou prix de gros [gaz naturel])* The field-gate price plus all transmission charges up to the point where a local distribution company receives the gas into its system for onward distribution to consumers.

Coal-bed Methane Gas *(Méthane des gisements de charbon)* The naturally occurring, dry, predominantly methane, gas produced during the transformation of organic material into coal. It is present as molecules adsorbed within the molecular structure of all coals, as gas in matrix porosity, as free gas in open fractures in coal, and as gas dissolved in ground water within the coal.

Coal Gasification *(Gazéification du charbon)* The production of a synthetic natural gas from coal.

Coal Liquefaction *(Liquéfaction du charbon)* The production of a synthetic crude oil or liquid fuel from coal.

Co-generation *(Coproduction)* A facility which produces steam heat as well as electricity, with a resultant overall improvement in energy conversion efficiency.

Commodity Charge *(Frais liés au produit)* A commodity charge is a charge payable by a gas purchaser in a sales contract for each unit of gas purchased. The unit charge generally covers the commodity component of the applicable pipeline toll and the cost of gas, and may include a portion of the fixed costs of the seller. (See also 'Demand Charge')

Competitive Marketing Program *(Programme de commercialisation sur les marchés concurrentiels)* A mechanism by which WGML has provided specific discounts to individual end-users of gas. Generally the distributor sells to the end user under the approved sales rate schedule. The distributor advises the pipeline of volumes sold each month. The pipeline rebates to the distributor the agreed upon discount for the preceding month's volumes and the distributor flows the rebate through to the end user. (WGML replaced CMPs with SGRs in January 1988.)

Condensate *(Condensat)* A mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities or at the inlet of a processing plant before the gas is processed in a plant.

Consuming Provinces (gas) *(Provinces consommatrices [gaz naturel])* Those provinces of Canada which consume more natural gas than they produce - Manitoba, Ontario and Quebec.

Continuous Casting *(Coulée en continu)* A process that directly casts molten steel in a primary mill into smaller and thinner sections without the need for reheating steel ingots.

Contract Demand *(Demande contractuelle)* A firm service which provides gas up to a specific maximum daily quantity. The buyer must pay a monthly demand charge regardless of the volumes taken and a commodity charge for the volumes actually taken.

Control Case *(Scénario de référence)* See Chapters 1 and 2 for assumptions in the Control Case.

Conventional Crude Oil *(Pétrole brut classique)* Crude oil which at a particular point in time can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil. For the purpose of this report conventional crude oil is categorized as light or heavy crude oil, based mainly on the refining processes required to produce useful products. Our heavy crude oil category includes both heavy crudes and crudes which are classified by some others as medium. Appendix A7-10 shows production from crude streams included in the National Energy Board's conventional light crude oil category and Appendix A7-13 shows production from crude streams included in the National Energy Board's heavy crude oil category.

Conventional Natural Gas *(Gaz naturel classique)* Natural gas occurring in a normal porous and permeable reservoir rock which at a particular point in time can be technically and economically produced using normal production practices.

Core Market (gas) *(Marché captif [gaz naturel])* Generally that part of the gas market that does not possess fuel switching capability in the near-term; typically, residential, commercial and small industrial users.

Crude Bitumen *(Bitume brut)* A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentanes, that has a viscosity greater than 10 000 MPa.s measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. Crude bitumen may contain sulphur and other non-hydrocarbon compounds and in its natural viscous state is not recoverable at a commercial rate through a well.

Crude Oil and Equivalent Hydrocarbons *(Pétrole brut et hydrocarbures équivalents)* Sometimes referred to as 'Crude Oil and Equivalent'. Includes light and heavy crude oil, pentanes plus, bitumen and synthetic crude oil.

Cyclic Steam Stimulation (Stimulation cyclique à vapeur) An improved recovery technique in which steam is injected into a reservoir through a well to reduce the viscosity of heavy crude oil. The well is then shut-in to allow the heat to dissipate and reduce the viscosity of the oil and the oil is subsequently produced using the same well through which the steam was injected.

Deferred Reserves *(Réserves reportées)* Established natural gas reserves which are not currently available to a market for a specific reason, usually their use in enhanced recovery of crude oil or NGL.

Debottlenecking *(Désétranglement)* A means of increasing processing capacity by expanding certain portions of a refinery which otherwise restrict throughput.

Degree Day *(Degré -jour)* A (heating) degree day is a measure of the extent to which the average daily temperature is below 18°C. For example, if the average daily temperature were 16°C for a given location for a 10-day period, the number of degree days recorded there would be 20. For days when the average temperature is warmer than 18°C, the degree days are recorded as zero. Degree days are used to indicate the amount of space heating required, other things being equal; for example, the higher the number of degree days, the colder the average recorded temperatures and the more space heating required.

Deliverability *(Livraison)* See 'Productive Capacity'.

Demand Charge *(Frais liés à la demande)* A fixed, usually monthly, obligation of a gas purchaser in a sales contract. It may cover some or all of a seller's fixed costs and is payable regardless of volumes actually taken.

Demand Management *(Gestion de la demande)* Measures promoted by electric utilities to favourably influence the amount and timing of customer electricity demand.

Development Contract *(Contrat de développement)* A development contract differs from a conventional gas purchase contract in that not all reserves are established at the time it is executed. The producer dedicates specific lands in which it has both existing established reserves and the right to explore for and develop new reserves. The specified date of first delivery gives the producer time to find and develop reserves and install production facilities.

Direct Sale or Direct Purchase *(Vente directe ou achat direct)* Natural gas supply purchase arrangements transacted directly between producers or brokers and end users at negotiated prices.

Discovered Recoverable Resources *(Ressources découvertes et récupérables)* Resources which are estimated at this time to be recoverable from known accumulations (that is accumulations which have been shown to exist by drilling, testing or production) using known technology. They include cumulative production, remaining reserves and "other discovered recoverable resources".

Displacement Volume (gas) *(Volume substitué [gaz naturel])* A direct purchase volume is a displacement volume when, assuming the absence of such direct purchase, the LDC could supply the account on a firm contract basis without itself contracting for additional firm volumes to accommodate the demand.

Economy Energy *(Énergie d'économie)* Electrical energy sold by one power system to another, to effect a saving in the cost of generation when the receiving system has adequate capacity to supply its own requirements.

Electric Arc Technology *(Technique de l'arc électrique)* Use of electrical arcs in a furnace to efficiently produce very high temperatures for applications such as metal melting and coating and industrial drying.

Electricity Production *(Production d'électricité)* The amount of electric energy expressed in kilowatt hours or multiples of kilowatt hours produced in a year. The determination of electric energy production takes into account various factors such as the type of service for which generating units were designed (e.g., peaking or base load) the availability of fuels, the cost of fuels, river water levels, and environmental constraints.

Emission Factor *(Facteur d'émission)* An estimate of the rate at which a substance is released to the atmosphere as a result of some activity (e.g., kg of SO_2 emitted per tonne of coal burned).

End Use Demand for Energy (or Secondary Energy Demand) *(Demande d'énergie pour utilisation finale [ou demande d'énergie secondaire])* Energy used by final consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for such non-energy purposes as petrochemical feedstock.

Energy Intensity *(Intensité énergétique)* In the industrial and commercial sectors and in transportation other than automobiles energy intensity is defined as the amount of energy per unit of production. In the residential sector it is energy use per household and for automobiles it is energy use per car. A measure of the efficiency with which energy is used in the economy as a whole is total end use energy per unit of GNP.

Enhanced Oil Recovery (or Enhanced Recovery) *(Récupération assistée)* See 'Recovery - Improved'.

Environmental Protection Agency The U.S. equivalent to Environment Canada.

Established Reserves (Oil and Gas) *(Réserves établies [pétrole et gaz naturel])* Those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgement portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty. This is a term that has been used historically in Canada, particularly by governments, and is typically comprised of proved reserves plus one-half probable reserves.

Ethane *(Éthane)* In addition to its normal scientific meaning, a mixture mainly of ethane which may contain some methane or propane.

Experimental Oil Project *(Projet expérimental sur le pétrole)* A pilot test to evaluate techniques for recovery of crude bitumen, crude oil, or condensate using methods that are considered untried and unproven in the particular situation.

Federal Energy Regulatory Commission The FERC is responsible for the regulation of all interstate trade in natural gas in the U.S. and administers prices for some U.S. gas which is still subject to price controls. It regulates the tolls and tariffs of interstate oil and natural gas pipelines and approves the construction of new facilities. It also regulates the transmission and wholesale sale of electricity in interstate commerce, and licenses non-federal hydroelectric projects.

Feedstock *(Charge d'alimentation)* Raw material supplied to a refinery or petrochemical plant.

Fieldgate Price (gas) *(Prix après traitement [gaz naturel])* The fieldgate is the point at which transfer of custody of gas, which has been gathered and undergone any processing to remove impurities and by-products, takes place from the producer to a pipeline company. More generally, fieldgate is used to specify a reference or delivery point on the production system. The term fieldgate price is used to refer to the price received for gas by producers, where producers are paying for gathering and processing.

Firm Energy *(Énergie garantie)* Electrical energy guaranteed to be available at all times during the period of agreement for its sale.

Firm Power *(Puissance garantie)* Electric power intended to be available at all times during the period covered by an agreement.

Firm Service (gas) *(Service garanti [gaz naturel])* A relatively high-priced transportation service which provides transportation of up to a maximum daily volume without interruption except under extraordinary circumstances.

Firm Service Tendered (gas) *(Service garanti offert [gaz naturel])* A transportation service which provides for different service levels in the winter and summer.

Fixed-toll Method *(Méthode de calcul basée sur des droits fixes)* The fixed-toll method sets pipeline tolls which do not vary from month to month with changes in throughput or variances in expenses. Fixed tolls are based on forecasts of costs and throughputs for a test year.

Flat Life *(Cycle de vie fixe)* That period of the producing life of a resource during which production is maintained at a constant rate.

Frontier Areas *(Régions pionnières)* Generally, the northern and offshore areas of Canada.

Fuel Efficiency (or Burner Tip Efficiency) *(Rendement du combustible [ou rendement à la pointe du brûleur])* The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation.

Fuel Switching Capability *(Capacité d'utilisation d'un combustible de remplacement)* A customer's ability to use two or more fuels.

Fugitive Emission *(Émission fugitive)* In this report, refers to any gaseous emission other than from combustion (e.g., escape of gases from refinery valves).

Gas Contract Year *(Année contractuelle du gaz)* 1 November to the following 31 October.

Gas Cycling *(Recyclage du gaz)* The reinjection of part or all of the produced natural gas into the reservoir after removal of natural gas liquids.

Gas-in-place *(Gaz en place)* see Initial Volume-in-Place

Gas Inventory Charge *(Frais de stockage de réserves de gaz)* A fixed charge or fee to cover the cost of holding gas reserves to supply a customer.

Gas Resources Sensitivities *(Sensibilités aux ressources en gaz)* See Chapter 1, and Section 6.11.

Heavy Crude Oil *(Pétrole brut lourd)* A collective term used to refer to conventional heavy crude oil and crude bitumen. In this report, heavy crude oil supply and demand numbers include heavy crude oil as well as any light fractions added to reduce viscosity to facilitate pipeline transportation but exclude any conventional heavy crude oil or bitumen upgraded to light crude oil.

Heavy Fuel Oil *(Mazout lourd)* In this report, includes bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).

High (or Low) Gas Resources *(Ressources élevées (ou faibles) en gaz)* See 'Gas Resources Sensitivities'.

High (or Low) Oil Price *(Prix élevé (ou bas) du pétrole)* See 'Oil Price Sensitivities'.

Hog Fuel *(Résidus de bois)* Fuel consisting of pulverized bark, shavings, sawdust, low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

Horizontal Well *(Puits horizontal)* A well which is directionally drilled to exploit certain specific types of reservoirs. In a horizontal well, the horizontal extension is that part of the wellbore beyond the point where it first deviates by 80 degrees or more from vertical.

Hybrid System *(Système hybride)* A dual fuel heating system using two alternative sources of energy.

Hydroelectric Generation *(Production hydro-électrique)* Electricity produced by an electric generator driven by a hydraulic turbine.

Independent Power Producers *(Producteurs d'électricité indépendants)* Electric power facilities built by private investors to serve load requirements of a utility or of an industry.

Incremental Cost or Replacement Cost *(Coût marginal ou coût de remplacement)* See 'Supply Cost'.

Infill Drilling *(Forage intercalaire)* The process of drilling additional wells within the defined pool outline of a natural gas or oil pool for the purpose of increasing reserves and/or productive capacity. For the purpose of this report increases in reserves are included in the improved recovery category.

Initial Reserves *(Réserves initiales)* Initial reserves is a term often used to refer to reserves prior to deduction of any production. Alternatively, initial reserves can be described as the sum of remaining reserves and cumulative production at the time of the estimate.

Initial Volume-In-Place *(Volume initial en place)* The gross volume of crude oil, natural gas and related substances estimated at a particular point in time to be initially contained in a reservoir, before any volume has been produced and without regard for the extent to which such volumes will be recovered.

In Situ Combustion *(Combustion in situ)* An improved recovery method in which a portion of the crude oil in a reservoir is burnt by injecting air or oxygen, the resultant heat causes the oil to break down into coke and a lighter oil, with the heated gases formed by the combustion process displacing the lighter oil toward the producing wells.

In Situ Recovery *(Récupération en place)* The process of recovering crude bitumen from oil sands other than by surface mining.

Interruptible Customer (gas) *(Client du service interruptible [gaz naturel])* A customer whose gas service is subject to curtailment for either capacity and/or supply reasons, at the option of the pipeline company or LDC.

Interruptible Energy *(Énergie interruptible)* Electric power and/or energy made available under an agreement that permits curtailment or cessation of availability at the option of the supplier.

Interruptible T-Service (gas) *(Service-T interruptible [gaz naturel])* An interruptible gas transportation service provided under contract for gas which is not owned by the pipeline company. The interruption is at the option of the pipeline company or distributor. There are two tiers of interruptible service. IS-1 is higher priority, offering less risk of interruption than IS-2, which is lower priority. The toll for IS-1 is higher than that for IS-2.

Kerogen *(Kérogène)* A solid bituminous substance occurring in certain shales that decomposes to oil and natural gas when heated.

Light Crude Oil *(Pétrole brut léger)* A collective term used to refer to conventional light crude oil, upgraded heavy crude oil, synthetic crude oil and pentanes plus. In this report, light crude oil supply and demand numbers exclude any light crude fractions added to heavy crude oil.

Light Fuel Oil *(Mazout léger)* Furnace fuel oil (No. 2 fuel oil).

Liquefied Petroleum Gases *(Gaz de pétrole liquéfiés)* In this report, includes propane and butanes, or combinations thereof.

Load Balancing *(Équilibrage de l'offre)* The balancing of gas supply to meet demand by using storage, other peak supply sources, curtailment of interruptible sales, or diversions from one delivery point to another.

Load Factor *(Facteur de charge)* The ratio of the average load over a designated period of time to the contracted maximum load, expressed in percent.

Marketable Natural Gas *(Gaz naturel commercialisable)* Natural gas which meets specifications for end use, whether it occurs naturally or results from the processing of raw natural gas. It excludes field and plant fuel and losses, excepting those related to downstream reprocessing plants. The heating value of marketable natural gas may vary considerably, depending upon its composition, and therefore quantities of reserves are usually expressed not only in volumes, but also in terms of energy content.

Methane *(Méthane)* In addition to its normal scientific meaning, a mixture of methane which ordinarily may contain ethane, nitrogen, helium or carbon dioxide.

Middle Distillates *(Distillats moyens)* The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.

Miscible Flooding *(Injection de fluides miscibles)* An improved recovery process in which a fluid, capable of mixing completely with the oil it contacts, is injected into an oil reservoir to increase recovery.

Natural Gas Liquids *(Liquides de gaz naturel)* Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, pentanes plus and condensate and may include small quantities of non-hydrocarbons.

Nitrogen Oxides (*Oxydes d'azote)* In this report, Includes nitrogen oxide (NO) and nitric dioxide (NO_2).

Non-Associated Gas *(Gaz non associé)* Natural gas found in a reservoir in which no crude oil is present at original reservoir conditions.

Non-Conventional Generation *(Production non classique)* The generation of electricity by any means other than hydroelectric generation; thermal generation using nuclear fuel, coal, oil or natural gas; gas turbine generation using oil or natural gas; or internal combustion generation. Examples would be solar power and wind energy.

Non-System Producer *(Producteur hors-réseau)* A gas producer who is not contracted to supply a pipeline or the pipeline's marketing subsidiary.

Non-Utility Generation *(Production par une société autre qu'un service public)* Electric power facilities built, owned and operated by specific industries or private investors to serve the industry's own electricity needs or to serve the electric utility load requirement.

Office of Fossil Energy, U.S. Department of Energy The Office of Fossil Energy took over the responsibility for approving exports and imports of natural gas from and into the U.S. in February 1989. Previously, this was the responsability of the Economic Regulatory Administration.

Oil-in-Place *(Pétrole en place)* See 'Initial Volume-in-Place'.

Oil Price Sensitivities *(Sensibilités aux prix du pétrole)* See Chapter 1, and Sections 2.1, 4.4, 6.12, and 7.10.

Oil Sands *(Sables pétrolifères ou sables bitumineux)* Deposits of sand or sandstone, or other sedimentary rocks containing crude bitumen.

Oil Shale *(Schiste pétrolifère)* A shale that contains kerogen.

Open Access *(Libre-accès)* The non-discriminatory access to pipeline transportation services.

Operating Demand Volumes *(Volumes de la demande opérationnelle)* Volumes specified in a distributor's CD contracts with a pipeline less the volumes deemed to have been displaced by direct sales, as determined under the NEB's rules established for defining displacement volumes.

Other Discovered Recoverable Resources *(Autres ressources découvertes et récupérables)* Those discovered resources that are estimated at this time to be recoverable using known technology but that have not yet been recognized as established reserves because of uncertain economic viability.

Particulate Matter *(Particules)* Small particles of material released to the atmosphere in either solid or liquid form.

Peak Demand (electricity) *(Demande de pointe [électricité])* The highest level of power demand by customers on a power system within a specified period, usually a year, (i.e., on a major utility, a minor utility or an individual industry generating its own electricity). The peak demand is measured in kilowatts or multiples of kilowatts.

Peak Demand (gas) *(Demande de pointe [gaz naturel])* The maximum amount of gas required by a customer or LDC over a short period of time (typically one day).

Peaking Capacity *(Capacité de pointe)* Electricity generating equipment which is available to meet peak demand.

Pentanes Plus *(Pentanes plus)* A mixture mainly of pentanes and heavier hydrocarbons which ordinarily may contain some butanes and which is obtained from the processing of raw gas, condensate or crude oil. For the purpose of this report pentanes plus includes condensate.

Permeability *(Perméabilité)* A measure of the capacity of a reservoir rock to transmit a fluid (liquid or gas).

Petroleum *(Pétrole)* A naturally occurring mixture of predominantly hydrocarbons in the gaseous, liquid or solid phase.

Plasma Arc Technology *(Technique de l'arc sous plasma)* Use of electrical arcs in a plasma furnace to efficiently produce very high temperatures for applications such as metal melting and coating, and industrial drying.

Potential Economic Growth *(Croissance Croissance économique potentielle)* Represents the upper bound to growth for a given unemployment rate; however, growth could exceed potential for a period of time if there are underutilized resources (e.g., if the unemployment rate at the beginning of the period were higher than the given rate). Potential growth is approximately equal to the sum of labour force and productivity growth.

Price Streaming (gas) *(Différenciation des prix [gaz naturel])* The charging of different commodity prices to different consumers, e.g., lower prices to industrial customers who have fuel switching capability than to residential customers who do not.

Primary Energy Demand *(Demande d'énergie primaire)* Represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (e.g. coal to electricity), and energy used by suppliers in providing energy to the market (e.g. pipeline fuel). (For the calculation of primary energy demand, see Appendix Table A10-1.) By definition, primary energy demand equals (end use energy demand) plus (energy supply industry use) minus (electricity and steam demand) plus (energy used to generate electricity and produce steam) plus (other conversion losses).

Primary Recovery *(Récupération primaire)* See 'Recovery - Primary'.

Private Cost *(Coût privé)* See 'Supply Cost'.

Productive Capacity *(Capacité de production)* The estimated rate at which natural gas, crude oil or crude bitumen can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the existence of gathering and processing facilities, and potential losses due to plant turnarounds

and operational problems. Productive Capacity is refered to by the ERCB as "Avalaible Supply". (See also 'Adjusted Productive Capacity')

Propane *(Propane)* In addition to its normal scientific meaning, a mixture mainly of propane which ordinarily may contain some ethane or butanes.

Pulping Liquor (also known as waste liquor or black liquor) *(Liqueur de pâte (aussi connue sous le nom de liqueur résiduaire ou de liqueur noire))* A substance primarily made up of lignin, other wood constituents, and chemicals which are by-products of the manufacture of chemical pulp. It can be burned in a boiler to produce steam or electricity, through thermal generation.

Rate of Take *(Taux d'extraction)* The initial rate at which gas will be produced from an entity such as a well, pool, field or area. It is usually expressed as a ratio. For example, a rate of take of 1:7300 means that 1 unit of production on a daily basis is obtained for each 7300 units of reserves for the entity under consideration.

Raw Natural Gas *(Gaz naturel brut)* Natural gas as it is produced from the reservoir prior to processing. It is gaseous at the conditions under which its volume is measured or estimated and it may include varying amounts of heavier hydrocarbons which liquefy at atmospheric conditions, and water vapor, and may also contain sulphur and other non-hydrocarbon compounds. Raw natural gas is generally not suitable for end use.

Recovery - Primary *(Récupération primaire)* The extraction of crude oil, natural gas and related substances from reservoirs utilizing only the natural energy available in the reservoirs.

Recovery - Enhanced *(Récupération assistée)* A term frequently used in Canada which is equivalent to improved recovery.

Recovery - Improved *(Récupération assistée)*The extraction of additional crude oil, natural gas and related substances from reservoirs through a production process other than natural depletion. Improved recovery includes both secondary and tertiary recovery processes, such as pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding and the use of miscible and immiscible displacement fluids.

Recovery - Secondary *(Récupération secondaire)* Secondary recovery is a term frequently used to describe the extraction of additional crude oil, natural gas and related substances from reservoirs through pressure maintenance schemes such as waterflooding or gas injection.

Recovery - Tertiary *(Récupération tertiaire)* Tertiary recovery is a term frequently used to describe the extraction of additional crude oil, natural gas and related substances from reservoirs using recovery methods other than natural depletion or pressure maintenance. A tertiary process can be implemented without a preceding secondary recovery scheme.

Refinery Acquisition Cost *(Coût d'achat à la raffinerie)* The delivered price of crude oil to a refinery, including all transportation charges to that point.

Remaining Capacity (electricity) *(Capacité restante [électricité])* The difference between Capacity Available and the System Peak Demand. The remaining capacity includes the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements and unforeseen loads. On a national basis it is the difference between the aggregate net capacity available of the various systems in Canada and the sum of the system peak demands, without allowance for time diversity between the loads of the several systems.

Remaining Reserves *(Réserves restantes)* Initial reserves less cumulative production at the time of the estimate.

Reprocessing Shrinkage *(Pertes en cours de retraitement)* That quantity of natural gas removed from main gas transmission systems at straddle plants and converted to NGL, expressed in either volume or energy units.

Reserves Additions *(Additions aux réserves)* Incremental changes to established reserves resulting from the discovery of new pools and/or revisions to reserve estimates for established pools.

Reserves Appreciation *(Valorisation des réserves)* Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates.

Reserves Life Index or **Reserves to Production Ratio** *(Indice de durée des réserves ou Ratio réserves/production)* Remaining reserves divided by annual production.

Reservoir *(Gisement)* A reservoir (or pool) is a porous and permeable underground rock formation containing a natural accumulation of crude oil, natural gas and related substances that is confined by im-

permeable rock or water barriers, and is individual and separate from other reservoirs.

Retrofitting - A house *(Réfection - d'une résidence)* Upgrading an existing house to reduce heat loss. Retrofitting includes measures such as adding insulation, caulking, weatherstripping and adding or improving storm windows and doors.

Retrofitting - A heating system *(Réfection - d'un système de chauffage)* Replacing selected system components to increase efficiency while retaining most of the original system.

R-2000 homes (*Maisons R-2000)* Type of new super efficient homes which are expected to meet the standard building code of the year 2000.

Self-Displacement *(Autosubstitution)* The purchase of natural gas by an LDC to displace gas it would otherwise obtain under its contracts with a pipeline or the pipeline's marketing subsidiary.

Shale Gas *(Gaz de schiste)* The dry, predominantly methane, gas produced from the fractures, micropores, and bedding planes of shales. In order to produce gas these shale reservoirs must be stimulated by acidifying, fracturing or use of explosives.

Shrinkage *(Pertes en cours de traitement)* That quantity of natural gas removed at field processing plants for recovery of liquids and by-products, removal of impurities, or used as fuel.

Solar Energy - Active System *(Énergie solaire - système actif)* Solar energy collection system which transfers heat captured from solar radiation through mechanical devices.

Solar Energy - Passive System *(Énergie solaire - système passif)* Solar energy collection system which captures solar radiation directly for space heating, water heating or other similar purposes, without the use of mechanical devices.

Solution Gas *(Gaz en solution)* Natural gas dissolved in crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.

Solvent Flooding *(Injection de fluides miscibles)* See 'Miscible Flooding'.

Sour Gas *(Gaz acide)* Natural gas containing hydrogen sulphide or carbon dioxide.

Spot Sale *(Vente sur le marché du disponible)* Generally, an interruptible sale of gas under a 30-day contract.

Stand Alone Upgrader *(Usine de valorisation indépendante)* An upgrading facility that is not associated with a mining plant or a refinery.

Steam Flood *(Méthode de l'injection de la vapeur)* An improved recovery technique in which steam is injected into a reservoir to reduce the viscosity of the crude oil. The injected steam, which condenses in the reservoir, also provides the energy to drive the crude oil to the producing wells.

Straddle Plant *(Usine de chevauchement)* A natural gas processing plant, located on a main gas transmission system, which extracts NGL from the gas stream.

Sulphur *(Soufre)* Sulphur, as used in the petroleum industry, is the elemental sulphur recovered by conversion of the hydrogen sulfide extracted from crude oil, natural gas or crude bitumen.

Sulphur Dioxide *(Dioxyde de soufre)* Refers to gaseous sulphur dioxide (SO_2). In some cases, emissions may contain small amounts of sulphur trioxide (SO_3) and sulphurous and sulphuric acid vapour. Excludes particulate or aerosol sulphate.

Supply Cost (*Coût des approvisionnements*) A gas or oil supply cost estimate expresses some or all costs associated with resource exploitation as that amount per unit of output which would recover the project costs, including the rate of return, over its life.

Supply costs can be calculated from either a private or social perspective. In this report we have used *private supply costs.* These costs include both the *direct* resource costs (exploration, development, production) and payments to various levels of government (taxes and royalties). They are calculated from the perspective of the firm using a discount rate which reflects the corporate cost of capital.

The costs included in the calculation may be incremental or average. In this report we have used *incremental supply costs,* which are based on the costs of the next unit of production.

In this report, the incremental costs for natural gas are adjusted downward by subtracting by-product revenues per unit of gas production in order to reflect the value of the natural gas liquids and sulphur which are produced as by-products of natural gas processing. In order to indicate that such an adjustment has been made, we refer to these costs as *net incremental supply costs.*

Synthetic Crude Oil *(Pétrole brut synthétique)* A mixture of hydrocarbons similar to crude oil derived by upgrading crude bitumen from oil sands, kerogen from oil shales, or other substances such as coal. It may contain sulphur or other non-hydrocarbon compounds.

Synthetic Natural Gas *(Gaz naturel synthétique)* Natural gas produced from petroleum liquids, coal or wood.

System Gas Resale *(Revente de gaz du réseau)* A form of buy/sell arrangement wherein the end user purchases gas from WGML immediately east of the Alberta/ Saskatchewan border at a discounted price, then resells the gas to WGML at the price at which WGML will sell the gas to the distributor. WGML then sells the gas to the distributor, again just east of the Alberta/Saskatchewan border, and the distributor is the shipper on TransCanada. The distributor then sells the gas to the end user under its normal rate schedule.

System Gas Sale *(Vente de gaz du réseau)* Gas sold by pipeline companies or their affiliates, eg. WGML.

Take-or-Pay Provision *(Clause de prise obligatoire)* A clause or provision in a contract requiring that gas contracted for, but not taken, will be paid for.

Thermal Generation *(Production thermique)* Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity in a generator. Normally, the fuel may be coal, oil, gas, or uranium (nuclear).

Thermal Processes *(Procédés thermiques)* Enhanced oil recovery processes in which heat is added to the reservoir to increase recovery.

Thermo-Mechanical Pulping Process *(Technique thermomécanique de la production de pâtes)* A process used in the pulp and paper industry. Electrically produced mechanical energy is used to steam and refine wood chips into pulp. The steaming process softens the wood chips with the result that the pulp produced is of a higher quality than that obtained from other processes. Recovered steam may be used for space heating or for drying pulp fibres.

Tight Gas *(Gaz d'une formation imperméable)* Natural gas contained in low permeability reservoirs.

TOPGAS charges *(Frais financier TOPGAS)* Sums paid to TOPGAS and TOPGAS II bank consortia under agreements whereby they assumed TransCanada's take-or-pay liabilities. Also refers to sums paid under Alberta government policy, adopted subsequent to the recommendation of the NEB (see *Reasons for Decision in the Matter of TransCanada Pipelines Limited, Availability of Services*, May 1986), that the financing costs be shared by non-system producers in Alberta.

Transfer Capability *(Capacité de transfert)* The overall capacity of interprovincial or international power lines, together with the associated electrical system facilities, to transfer power and energy from one electrical system to another.

Ultimate Recoverable Resource Potential *(Potentiel ultime de ressources récupérables)* An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. It consists of discovered recoverable resources (cumulative production, remaining established reserves and other discovered resources) and of undiscovered recoverable resources.

Unauthorized Overrun Volumes (gas) *(Volumes de dépassement non autorisés [gaz naturel])* Volumes shipped in excess of those contracted for.

Unbundled Rate *(Taux séparé)* A rate for an individual, separate service offered by a pipeline or distributor.

Unconventional Crude Oil *(Pétrole brut non classique)* Crude oil which is not classified as conventional crude oil. An example of unconventional crude oil would be crude bitumen.

Unconventional Natural Gas *(Gaz naturel non classique)* Natural gas which is not classified as conventional natural gas. An example of unconventional natural gas would be coalbed methane.

Undiscovered Recoverable Resources *(Ressources récupérables pas encore découvertes)* Resources that are estimated at this time to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but which have not yet been shown to exist by drilling, testing or production.

Upgrading (*Valorisation)* The processing of bitumen or heavy crude oil into a synthetic crude oil.

User costs *(Coûts d'utilisation)* See Chapter 6, Annex 1.

Viscosity *(Viscosité)* The measure of the resistance of a fluid to flow.

Volatile Organic Compounds (*Composés organiques volatils*) Includes only photochemically reactive hydrocarbons. Excludes methane, ethane and chlorinated organics.

Waterflooding *(Injection d'eau)* An improved recovery process in which water is injected into a reservoir to increase recovery.

Wellhead *(Tête du puits)* Specifically, the equipment at the top of a well for maintaining control of the well. More generally, it is used to specify a reference or delivery point on the production system.

Wellhead Price (gas) *(Prix à la tête du puits [gaz naturel])* The price received for gas by producers, net of any gathering or processing costs.

Wheeling *(Transit)* The transmission of electricity from one utility, through the transmission network of another utility, for delivery to a third party.

Wood Gasification *(Gazéification du bois)* The production of a synthetic natural gas from wood.

Wood Liquefaction *(Liquéfaction du bois)* The production of liquids (e.g. methanol) from wood.

Wood Waste *(Résidus de bois)* Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

Wood Wastes *(Déchets de bois)* Refers to wood waste and pulping liquor.

World Oil Price *(Prix mondial du pétrole)* In this report, the official selling price of West Texas Intermediate crude oil at Chicago.

Appendix 2
Table A2-1
World Oil Prices

	1975	1976	1977	1978	1979	1980	1981	1982	1983
WTI At Cushing:									
($U.S. 1990 / Barrel)	30.58	31.65	31.96	30.50	38.09	58.01	50.07	42.60	38.17
($U.S. 1990 / Cubic Metre)	192.45	199.20	201.13	191.92	239.69	365.03	315.09	268.09	240.19
Netback Price of Crude at Edmonton:									
($U.S. 1990 / Cubic Metre)	181.30	188.49	191.30	181.54	229.94	355.93	305.65	258.12	230.25
($C 1990 / Cubic Metre)	201.14	198.35	217.98	224.62	288.92	440.33	383.57	326.42	287.63
($C 1990 / Barrel)	31.96	31.52	34.64	35.69	45.91	69.97	60.95	51.87	45.71

	1984	1985	1986	1987	1988	1989	1990	1991	1992
WTI At Cushing:									
($U.S. 1990 / Barrel)	35.58	32.93	17.27	21.47	17.32	20.40	24.49	20.30	20.61
($U.S. 1990 / Cubic Metre)	223.93	207.26	108.68	135.14	108.97	128.37	154.11	127.76	129.69
Netback Price of Crude at Edmonton:									
($U.S. 1990 / Cubic Metre)	214.46	198.21	99.35	124.65	98.66	118.30	149.08	122.78	124.77
($C 1990 / Cubic Metre)	283.20	276.73	141.52	165.98	121.01	138.63	173.94	149.30	152.63
($C 1990 / Barrel)	45.00	43.97	22.49	26.37	19.23	22.03	27.64	23.72	24.25

	1993	1994	1995	1996	1997	1998	1999	2000	2001
WTI At Cushing:									
($U.S. 1990 / Barrel)	20.92	21.24	21.56	21.88	22.21	22.55	22.89	23.24	23.59
($U.S. 1990 / Cubic Metre)	131.65	133.64	135.66	137.71	139.80	141.91	144.06	146.23	148.44
Netback Price of Crude at Edmonton:									
($U.S. 1990 / Cubic Metre)	126.78	128.82	130.88	132.98	135.11	137.26	139.45	141.67	143.92
($C 1990 / Cubic Metre)	157.60	160.94	164.08	166.60	168.67	170.07	171.87	174.39	176.61
($C 1990 / Barrel)	25.04	25.57	26.07	26.47	26.80	27.03	27.31	27.71	28.07

	2002	2003	2004	2005	2006	2007	2008	2009	2010
WTI At Cushing:									
($U.S. 1990 / Barrel)	23.95	24.31	24.67	25.05	25.43	25.81	26.20	26.60	27.00
($U.S. 1990 / Cubic Metre)	150.69	152.97	155.28	157.63	160.01	162.43	164.88	167.38	169.91
Netback Price of Crude at Edmonton:									
($U.S. 1990 / Cubic Metre)	146.21	148.52	150.87	153.25	155.66	158.11	160.60	163.12	165.67
($C 1990 / Cubic Metre)	178.54	180.79	182.65	184.39	186.07	188.06	189.87	191.45	192.14
($C 1990 / Barrel)	28.37	28.73	29.02	29.30	29.57	29.88	30.17	30.42	30.53

Note: 1990 is last year of actual data.

Table A2-2
Real Gross Domestic Product Growth Rates - Canada and Regions

	Average Annual Growth Rates				
	1986-1990	1990-1995	1995-2000	2000-2005	2005-2010
Atlantic Provinces	2.5	2.1	2.1	1.8	1.3
Newfoundland	3.0	3.6	3.8	2.4	-0.4
Prince Edward Island	1.7	1.1	1.2	1.4	1.7
Nova Scotia	2.2	1.8	1.8	1.5	1.8
New Brunswick	2.7	1.6	1.5	1.7	1.8
Central Canada	3.7	2.7	2.5	2.5	2.7
Quebec	4.1	2.5	2.2	2.2	2.2
Ontario	3.5	2.8	2.6	2.7	2.9
Prairies	2.2	1.9	1.4	1.8	1.6
Manitoba	1.7	1.4	1.9	1.5	2.1
Saskatchewan	0.7	1.3	1.2	1.1	1.8
Alberta	2.9	2.2	1.4	2.0	1.5
British Columbia and Territories	5.8	2.0	2.1	2.3	2.1
Canada	3.4	2.4	2.2	2.3	2.3

Notes: The numbers on this table have been rounded.

Table A3-1
Alberta Natural Gas Fieldgate Price

1990 Dollars per Gigajoule

1986	1987	1988	1989	1990	1991	1992	1993	1994
2.55	1.78	1.62	1.52	1.47	1.41	1.41	1.60	1.79

1995	1996	1997	1998	1999	2000	2001	2002	2003
1.98	2.16	2.35	2.49	2.62	2.77	2.91	3.04	3.17

2004	2005	2006	2007	2008	2009	2010
3.28	3.40	3.51	3.62	3.77	3.90	4.02

Note: 1989 is last year of actual data.

Appendix 4

Table A4-1

Real Average Retail Prices by Region and Sector

($1990/Input Gigajoule)

Atlantic

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Light Fuel Oil	8.00	8.82	8.53	8.61	8.72	8.80	8.87	9.13	9.39	9.59
Electricity	17.02	16.84	18.08	18.13	18.13	18.13	18.13	18.13	18.13	18.13
Commercial										
Light Fuel Oil	6.78	7.60	7.22	7.31	7.42	7.49	7.57	7.83	8.08	8.28
Heavy Fuel Oil	3.45	4.37	4.06	4.33	4.65	4.80	4.94	5.37	5.65	5.87
Electricity	23.76	22.70	24.36	24.43	24.43	24.43	24.43	24.43	24.43	24.43
Industrial										
Heavy Fuel Oil	2.76	3.61	3.40	3.64	3.91	4.04	4.17	4.56	4.86	5.19
Electricity	14.46	14.29	15.62	15.70	15.74	15.78	15.79	15.91	16.11	16.56

Quebec

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Light Fuel Oil	8.18	8.94	8.63	8.64	8.76	8.84	8.92	9.20	9.47	9.69
Electricity	14.12	14.56	15.67	15.86	16.15	16.15	16.15	16.15	16.15	16.15
Natural Gas	7.05	6.86	7.28	7.13	7.30	7.48	7.52	8.39	9.08	9.77
Commercial										
Light Fuel Oil	6.93	7.69	7.31	7.33	7.45	7.53	7.61	7.89	8.16	8.38
Heavy Fuel Oil	3.84	4.24	4.37	4.63	4.97	5.13	5.29	5.74	6.04	6.28
Electricity	17.14	17.14	21.31	21.58	21.97	21.97	21.97	21.97	21.97	21.97
Natural Gas	5.74	5.58	5.93	5.87	6.05	6.23	6.30	7.17	7.86	8.55
Industrial										
Heavy Fuel Oil	3.25	3.50	3.38	3.89	4.18	4.33	4.46	4.88	5.20	5.56
Electricity	9.55	9.82	10.88	11.04	11.28	11.30	11.31	11.40	11.54	11.87
Natural Gas	3.48	3.57	3.88	4.31	4.52	4.71	4.82	5.68	6.40	7.30

Note: 1989 is last year of actual data.

Table A4-1 (Continued)
Real Average Retail Prices by Region and Sector

($1990/Input Gigajoule)

Ontario

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Light Fuel Oil	8.62	9.32	9.22	9.30	9.41	9.49	9.56	9.83	10.09	10.30
Electricity	15.84	16.23	17.80	18.43	19.11	19.11	19.11	19.11	19.11	19.99
Natural Gas	5.38	5.22	5.59	5.51	5.67	5.83	5.88	6.69	7.34	7.98
Commercial										
Light Fuel Oil	7.30	8.00	7.81	7.90	8.00	8.08	8.15	8.42	8.69	8.90
Heavy Fuel Oil	3.43	4.23	4.05	4.32	4.63	4.78	4.92	5.36	5.65	5.87
Electricity	18.50	19.11	23.19	24.01	24.90	24.90	24.90	24.90	24.90	26.04
Natural Gas	4.35	4.22	4.52	4.52	4.69	4.86	4.92	5.74	6.39	7.03
Industrial										
Heavy Fuel Oil	2.74	3.50	3.39	3.63	3.89	4.03	4.15	4.56	4.86	5.20
Electricity	10.54	11.36	13.37	13.88	14.42	14.46	14.47	14.58	14.77	15.88
Natural Gas	2.79	2.88	3.14	3.30	3.51	3.70	3.82	4.69	5.43	6.27

Manitoba

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Light Fuel Oil	8.76	9.46	9.37	9.46	9.57	9.64	9.72	9.99	10.25	10.46
Electricity	11.80	11.92	12.76	12.76	12.76	12.76	12.76	12.16	11.59	11.05
Natural Gas	4.59	4.41	4.67	4.59	4.77	4.94	4.99	5.84	6.53	7.21
Commercial										
Light Fuel Oil	6.21	6.95	6.62	6.70	6.82	6.90	6.98	7.26	7.54	7.76
Heavy Fuel Oil	5.21	6.42	6.09	6.47	6.89	7.12	7.34	8.00	8.43	8.78
Electricity	18.61	18.53	19.23	19.23	19.23	19.23	19.23	18.33	17.47	16.65
Natural Gas	3.47	3.32	3.51	3.51	3.70	3.87	3.94	4.80	5.49	6.17
Industrial										
Heavy Fuel Oil	2.74	3.49	3.35	3.57	3.82	3.95	4.07	4.47	4.78	5.11
Electricity	9.63	10.09	10.65	10.68	10.71	10.73	10.74	10.31	9.96	9.75
Natural Gas	2.28	2.34	2.53	2.68	2.90	3.09	3.21	4.08	4.81	5.63

Note: 1989 is last year of actual data.

($1990/Input Gigajoule)

Saskatchewan

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Light Fuel Oil	7.95	8.65	8.51	8.59	8.70	8.78	8.85	9.12	9.39	9.60
Electricity	18.32	17.52	17.70	17.70	17.70	17.70	17.70	17.70	17.70	17.70
Natural Gas	3.98	3.96	4.14	4.15	4.34	4.52	4.70	5.49	6.15	6.81
Commercial										
Light Fuel Oil	5.78	6.48	6.19	6.27	6.38	6.46	6.53	6.80	7.07	7.28
Heavy Fuel Oil	4.86	5.97	5.62	5.95	6.32	6.53	6.73	7.34	7.75	8.07
Electricity	31.55	30.17	30.21	30.21	30.21	30.21	30.21	30.21	30.21	30.21
Natural Gas	3.53	3.50	3.65	3.66	3.85	4.04	4.23	5.05	5.71	6.37
Industrial										
Heavy Fuel Oil	2.74	3.48	3.32	3.52	3.75	3.89	4.01	4.41	4.71	5.05
Electricity	18.07	17.84	18.10	18.14	18.19	18.23	18.24	18.38	18.62	19.14
Natural Gas	2.31	2.34	2.45	2.46	2.67	2.89	3.11	4.03	4.78	5.62

Alberta

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Light Fuel Oil	7.34	8.04	7.85	7.94	8.05	8.12	8.20	8.47	8.73	8.94
Electricity	13.88	15.05	17.48	17.48	17.48	17.48	17.48	17.48	17.48	17.48
Natural Gas	3.32	3.33	3.50	3.42	3.63	3.80	3.97	4.79	5.43	6.08
Commercial										
Light Fuel Oil	5.46	6.16	5.84	5.93	6.04	6.11	6.19	6.46	6.72	6.93
Heavy Fuel Oil	2.83	3.48	3.25	3.43	3.64	3.76	3.87	4.23	4.47	4.66
Electricity	18.06	17.27	19.68	19.68	19.68	19.68	19.68	19.68	19.68	19.68
Natural Gas	2.48	2.49	2.59	2.52	2.73	2.90	3.07	3.89	4.53	5.18
Industrial										
Heavy Fuel Oil	2.74	3.48	3.29	3.48	3.70	3.83	3.96	4.35	4.66	4.99
Electricity	11.07	10.93	12.61	12.64	12.68	12.71	12.71	12.81	12.98	13.34
Natural Gas	1.57	1.61	1.69	1.73	1.98	2.21	2.45	3.32	4.04	4.84

Note: 1989 is last year of actual data.

Table A4-1 (Continued)
Real Average Retail Prices by Region and Sector

($1990/Input Gigajoule)	British Columbia and Territories									
	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Light Fuel Oil	8.57	9.27	9.17	9.25	9.36	9.44	9.51	9.78	10.04	10.25
Electricity	13.37	13.17	13.70	13.28	12.89	12.89	12.89	12.89	12.89	12.89
Natural Gas	5.03	4.70	4.93	4.85	4.95	5.12	5.28	6.04	6.58	7.05
Commercial										
Light Fuel Oil	7.26	8.01	7.74	7.83	7.94	8.02	8.10	8.39	8.67	8.89
Heavy Fuel Oil	3.34	4.22	4.11	4.47	4.86	4.94	5.02	5.32	5.60	5.83
Electricity	17.90	17.63	18.01	17.46	16.94	16.94	16.94	16.94	16.94	16.94
Natural Gas	4.55	4.46	4.64	4.56	4.66	4.84	5.01	5.81	6.38	6.88
Industrial										
Heavy Fuel Oil	2.67	3.49	3.44	3.75	4.09	4.17	4.24	4.52	4.83	5.16
Electricity	9.54	9.71	10.05	9.76	9.50	9.52	9.53	9.60	9.72	9.99
Natural Gas	1.78	2.70	2.84	2.79	2.96	3.22	3.48	4.56	5.18	5.83

Note: 1989 is last year of actual data.

Table A4-2

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Historical Data

Canada

(Petajoules)

	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
Sectoral Demand										
Residential	1133.9	1182.5	1200.4	1280.6	1243.3	1324.0	1321.8	1348.1	1309.0	1368.9
Commercial	598.2	630.9	662.1	751.0	711.9	744.2	696.7	787.4	779.0	799.2
Industrial	1485.3	1560.7	1838.1	1936.5	2084.8	2192.0	2019.8	2090.2	2216.3	2247.5
Transportation - Road	918.2	970.8	1006.5	1079.0	1181.3	1235.7	1286.2	1361.7	1406.3	1450.3
- Air,Rail, Marine	290.2	303.8	312.9	333.6	359.4	365.8	338.1	329.7	330.9	349.0
- Total	1208.4	1274.5	1319.5	1412.6	1540.7	1601.4	1624.3	1691.4	1737.2	1799.4
Non-Energy [a]	238.1	287.6	293.6	319.1	362.0	361.2	356.0	396.9	462.0	483.5
Total End Use	**4663.9**	**4936.2**	**5313.6**	**5699.9**	**5942.7**	**6222.9**	**6018.6**	**6314.0**	**6503.6**	**6698.5**
Own Use	321.8	355.1	378.1	412.9	445.6	461.9	471.1	471.2	480.1	508.6
Electricity and Steam Generation [b][d]	942.3	1101.3	1187.3	1290.7	1443.6	1501.3	1525.0	1623.4	1755.2	1846.5
Other Conversions	190.7	224.0	207.4	210.3	240.3	236.2	222.2	233.2	214.2	222.4
Total Own Use and Conversions	**1454.8**	**1680.4**	**1772.7**	**1914.0**	**2129.6**	**2199.4**	**2218.3**	**2327.8**	**2449.5**	**2577.5**
Less Electricity, Steam, Coke and Coke Oven Gas	840.1	915.9	938.4	1015.5	1103.0	1167.4	1158.3	1227.1	1266.9	1334.6
Primary Energy Demand	**5278.7**	**5700.8**	**6147.8**	**6598.4**	**6969.3**	**7254.9**	**7078.6**	**7414.8**	**7686.2**	**7941.4**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	6.0	11.8	47.2	74.3	173.2	168.5	144.2	199.7	301.7	357.7
Hydro [b]	527.2	555.7	567.8	631.9	660.9	734.5	707.6	748.1	768.4	815.0
Oil	3016.9	3247.3	3309.1	3516.8	3665.1	3763.7	3673.0	3786.5	3811.9	3899.8
Natural Gas	995.5	1104.1	1222.4	1402.4	1481.4	1573.5	1589.1	1595.5	1693.8	1742.4
NGL-Gas Plant	45.8	39.3	45.3	53.9	58.9	73.4	67.3	69.6	65.2	36.9
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.6	2.6
Coal	614.9	674.0	647.6	595.7	584.5	580.7	602.3	654.6	681.1	685.3
Renewables and Others	72.5	68.7	308.4	323.3	345.4	360.6	295.2	358.0	361.5	401.6

Notes: [a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Historical Data Canada

(Petajoules)

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Sectoral Demand										
Residential	1383.8	1396.5	1323.6	1378.1	1335.3	1329.5	1392.0	1361.4	1295.6	1401.7
Commercial	809.0	778.6	800.8	826.1	819.0	824.1	821.3	832.9	781.3	847.3
Industrial	2404.4	2399.4	2276.9	2116.4	2109.6	2263.0	2342.3	2427.4	2527.6	2632.2
Transportation - Road	1523.0	1544.6	1505.7	1397.2	1363.2	1397.9	1414.5	1434.8	1475.1	1536.3
- Air,Rail,Marine	403.1	417.2	406.6	347.5	314.7	327.0	320.0	312.7	336.2	372.1
- Total	1926.1	1961.8	1912.3	1744.7	1677.9	1724.9	1734.5	1747.5	1811.2	1908.4
Non-Energy [a]	544.5	524.4	527.2	452.9	495.8	539.6	607.0	601.8	658.8	666.1
Total End Use	**7067.9**	**7060.8**	**6840.7**	**6518.2**	**6437.6**	**6681.0**	**6897.0**	**6970.9**	**7074.6**	**7455.6**
Own Use	520.7	516.1	483.7	459.1	453.0	490.9	518.8	496.3	515.9	553.7
Electricity and Steam Generation [b][d]	1987.8	2079.9	2147.1	2183.4	2312.0	2474.2	2577.4	2684.8	2827.6	2990.8
Other Conversions	251.1	234.4	210.1	182.5	183.1	212.4	202.8	195.4	195.6	193.6
Total Own Use and Conversions	**2759.6**	**2830.4**	**2840.9**	**2825.0**	**2948.0**	**3177.5**	**3299.0**	**3376.5**	**3539.1**	**3738.1**
Less Electricity, Steam, Coke and Coke Oven Gas	1415.6	1464.4	1470.9	1463.8	1526.3	1631.7	1699.0	1740.7	1794.7	1873.1
Primary Energy Demand	**8411.9**	**8426.9**	**8210.7**	**7879.4**	**7859.4**	**8226.8**	**8497.0**	**8606.7**	**8819.1**	**9320.6**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	429.0	455.8	488.4	481.3	570.3	605.3	693.7	811.8	877.3	925.6
Hydro [b]	833.0	844.9	863.7	838.2	866.6	928.3	973.8	1008.9	1001.5	1020.5
Oil	4053.6	3964.6	3705.8	3314.2	3086.8	3063.7	3045.4	3062.2	3144.7	3257.6
Natural Gas	1836.7	1786.8	1764.1	1805.8	1831.6	1981.3	2099.1	2061.0	2049.9	2262.3
NGL-Gas Plant	59.5	70.3	71.0	65.6	65.1	77.4	86.2	67.5	72.0	96.7
Ethane	13.5	25.3	34.5	22.2	34.6	54.4	68.6	83.7	109.3	110.1
Coal	763.5	823.7	842.3	895.9	925.5	1048.7	1015.7	967.6	1010.2	1094.4
Renewables and Others	423.2	455.3	440.8	456.2	479.1	467.8	514.5	543.9	554.2	553.5

Notes: [a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

Canada

(Petajoules)

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	1491.6	1466.0	1521.4	1525.2	1529.7	1533.6	1537.3	1565.1	1600.1	1644.7
Commercial	889.4	880.1	915.5	925.0	930.2	938.4	948.4	996.6	1048.0	1100.0
Industrial	2628.9	2597.3	2634.7	2687.1	2779.2	2872.2	2950.3	3207.6	3524.8	3868.2
Transportation - Road	1559.9	1534.0	1518.2	1521.9	1528.1	1536.2	1545.9	1597.2	1647.3	1694.2
- Air, Rail, Marine	390.1	383.2	387.4	403.0	412.8	420.6	427.3	452.8	466.6	489.7
- Total	1950.0	1917.2	1905.6	1924.9	1940.9	1956.8	1973.1	2050.0	2113.8	2184.0
Non-Energy [a]	666.9	648.4	668.3	711.1	722.4	734.0	780.7	856.0	921.1	993.7
Total End Use	**7626.8**	**7509.0**	**7645.5**	**7773.3**	**7902.4**	**8034.9**	**8189.8**	**8675.2**	**9207.8**	**9790.6**
Own Use	578.3	551.0	556.0	574.4	584.5	593.2	600.8	619.2	646.1	665.0
Electricity and Steam Generation [b][d]	3069.5	2909.1	3091.5	3184.9	3319.9	3372.2	3424.3	3607.6	3838.6	4195.0
Other Conversions	185.9	190.6	197.9	204.6	214.0	225.8	234.0	247.6	261.6	274.3
Total Own Use and Conversions	**3833.7**	**3650.8**	**3845.5**	**3963.9**	**4118.3**	**4191.2**	**4259.1**	**4474.4**	**4746.3**	**5134.3**
Less Electricity, Steam, Coke and Coke Oven Gas	1914.0	1877.3	1926.2	1968.4	2018.9	2072.5	2119.7	2270.2	2438.4	2619.8
Primary Energy Demand	**9546.5**	**9282.5**	**9564.8**	**9768.8**	**10001.8**	**10153.7**	**10329.3**	**10879.5**	**11515.7**	**12305.1**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	892.2	830.9	1093.3	1209.6	1333.0	1337.6	1339.4	1280.9	1238.9	1388.3
Hydro [b]	937.2	1027.0	1048.3	1071.8	1085.7	1098.0	1106.7	1176.4	1267.6	1353.6
Oil	3392.8	3328.1	3278.3	3299.0	3334.2	3369.0	3375.3	3529.6	3762.4	4105.8
Natural Gas	2405.9	2294.4	2361.3	2418.1	2473.5	2524.5	2574.9	2749.6	2846.4	2863.6
NGL-Gas Plant	131.5	128.0	131.4	151.8	153.3	154.9	156.4	162.4	168.3	173.7
Ethane	120.7	120.8	121.2	121.6	122.1	122.5	158.1	178.0	180.8	183.9
Coal	1123.0	1018.8	991.1	952.5	947.9	988.1	1052.5	1227.0	1467.6	1639.8
Renewables and Others	543.2	534.4	539.8	544.2	552.1	559.0	566.0	575.5	583.8	596.4

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions
Atlantic

(Petajoules)

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	118.8	121.2	122.7	122.7	122.7	122.8	123.0	123.6	124.3	125.6
Commercial	61.9	62.7	63.5	64.7	65.5	66.1	66.6	69.0	71.7	74.3
Industrial	154.2	148.7	150.5	151.3	153.6	156.8	158.8	171.7	179.7	183.9
Transportation - Road	127.3	125.6	124.7	125.2	125.8	126.4	127.0	130.0	132.4	134.7
- Air, Rail, Marine	53.2	53.2	54.4	57.0	58.9	60.4	61.6	66.1	68.7	72.9
- Total	180.5	178.8	179.1	182.2	184.7	186.8	188.6	196.1	201.1	207.6
Non-Energy [a]	20.6	20.6	21.5	22.0	22.6	23.1	23.5	25.4	27.2	28.9
Total End Use	**536.0**	**532.0**	**537.3**	**542.9**	**549.2**	**555.7**	**560.4**	**585.8**	**604.0**	**620.3**
Own Use	49.8	47.7	46.1	47.1	47.8	48.2	47.9	47.3	49.1	51.5
Electricity and Steam Generation [b][d]	365.6	356.3	383.3	384.3	390.7	393.3	410.6	433.2	467.4	506.9
Other Conversions	0.6	6.4	6.7	6.9	7.2	7.6	7.8	7.9	8.5	9.5
Total Own Use and Conversions	**416.0**	**410.4**	**436.1**	**438.3**	**445.7**	**449.1**	**466.3**	**488.4**	**525.0**	**567.9**
Less Electricity, Steam, Coke and Coke Oven Gas	130.5	134.2	136.4	140.0	143.2	147.0	150.7	165.8	175.0	182.4
Primary Energy Demand	**821.5**	**808.2**	**836.9**	**841.2**	**851.7**	**857.8**	**876.0**	**908.4**	**954.1**	**1005.8**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	42.2	39.2	36.5	36.5	36.5	39.2	39.2	39.2	39.2	39.2
Hydro [b]	116.3	140.0	158.1	158.0	157.9	157.8	157.6	178.4	198.7	199.1
Oil	510.7	476.7	469.5	467.6	476.2	480.3	459.1	464.1	483.5	516.6
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NGL-Gas Plant	2.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	76.8	79.7	99.7	106.0	106.9	106.4	146.0	155.6	161.1	177.8
Renewables and Others	73.2	72.5	73.0	73.0	74.0	73.9	74.0	70.9	71.4	72.9

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions
Quebec

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	327.1	321.3	332.7	332.0	331.7	331.4	330.8	332.3	336.4	342.6
Commercial	189.0	191.3	192.3	193.9	195.2	197.0	199.3	209.8	219.9	229.7
Industrial	562.6	568.4	574.3	585.7	602.1	621.2	636.9	679.6	725.5	785.0
Transportation - Road	340.8	335.5	333.2	334.8	336.7	338.7	341.2	351.9	360.5	369.2
- Air, Rail, Marine	71.7	68.1	68.9	71.7	73.4	74.7	75.8	79.7	81.6	85.2
- Total	412.4	403.5	402.1	406.5	410.1	413.4	417.0	431.6	442.1	454.4
Non-Energy [a]	88.7	90.2	92.7	95.1	97.7	100.3	102.8	114.4	127.3	141.9
Total End Use	**1579.9**	**1574.7**	**1594.2**	**1613.2**	**1636.8**	**1663.3**	**1686.8**	**1767.8**	**1851.1**	**1953.5**
Own Use	101.9	98.6	98.3	100.9	102.6	105.3	107.0	108.9	112.7	114.8
Electricity and Steam Generation [b][d]	517.3	526.5	538.5	552.7	565.5	581.4	591.5	626.5	666.9	737.1
Other Conversions	0.0	5.7	5.9	6.1	6.3	6.6	6.8	7.2	7.5	8.0
Total Own Use and Conversions	**619.2**	**630.9**	**642.7**	**659.7**	**674.5**	**693.4**	**705.3**	**742.5**	**787.2**	**859.8**
Less Electricity, Steam, Coke and Coke Oven Gas	594.7	581.6	594.9	607.5	621.6	638.4	652.5	703.1	760.3	821.2
Primary Energy Demand	**1604.4**	**1624.0**	**1642.0**	**1665.4**	**1689.6**	**1718.3**	**1739.6**	**1807.2**	**1878.0**	**1992.1**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	58.3	50.2	61.7	61.7	61.7	61.7	61.7	61.7	61.7	61.7
Hydro [b]	441.6	453.8	470.2	484.4	496.6	512.6	523.1	558.1	598.5	653.9
Oil	743.9	740.3	728.8	734.5	741.2	751.6	758.8	794.6	839.6	909.5
Natural Gas	217.6	230.7	230.6	233.1	237.2	237.4	239.4	229.9	211.1	195.4
NGL-Gas Plant	16.5	16.5	17.1	17.4	17.7	18.0	18.4	19.8	21.3	22.7
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	21.3	27.0	27.5	28.4	29.5	30.7	31.6	33.4	35.3	37.2
Renewables and Others	105.2	105.4	106.1	106.0	105.7	106.3	106.7	109.7	110.5	111.7

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions
Ontario

(Petajoules)

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	552.2	534.7	566.3	569.0	571.7	574.0	576.1	590.3	609.3	628.6
Commercial	341.2	330.4	347.7	351.6	352.2	355.3	359.5	380.8	403.8	426.5
Industrial	904.7	871.5	886.9	907.4	943.7	984.7	1017.3	1101.2	1195.8	1324.7
Transportation - Road	563.9	560.4	559.5	565.6	569.3	573.3	577.8	603.9	631.6	653.3
- Air, Rail, Marine	109.0	104.4	105.6	110.0	112.7	115.0	117.1	125.6	131.1	139.4
- Total	672.8	664.8	665.0	675.6	682.0	688.4	694.9	729.5	762.7	792.7
Non-Energy [a]	225.1	209.9	211.3	213.6	217.1	221.1	225.5	248.9	275.7	306.4
Total End Use	**2695.9**	**2611.3**	**2677.1**	**2717.1**	**2766.7**	**2823.5**	**2873.3**	**3050.6**	**3247.2**	**3478.9**
Own Use	194.2	177.9	180.9	185.5	189.4	191.5	193.5	200.8	210.8	222.6
Electricity and Steam Generation [b][d]	1254.6	1167.8	1316.9	1380.8	1479.1	1499.4	1524.7	1577.0	1661.2	1834.7
Other Conversions	171.6	154.5	160.0	164.4	172.8	183.4	190.5	201.6	212.3	223.6
Total Own Use and Conversions	**1620.4**	**1500.2**	**1657.8**	**1730.7**	**1841.3**	**1874.2**	**1908.7**	**1979.4**	**2084.3**	**2280.9**
Less Electricity, Steam, Coke and Coke Oven Gas	721.4	699.6	723.9	740.9	763.4	788.2	808.7	858.7	923.1	1002.9
Primary Energy Demand	**3594.9**	**3411.9**	**3611.1**	**3706.9**	**3844.5**	**3909.5**	**3973.3**	**4171.3**	**4408.4**	**4756.9**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	791.6	741.5	995.1	1111.4	1234.8	1236.7	1238.5	1180.0	1138.0	1287.4
Hydro [b]	139.6	144.8	139.8	140.4	140.4	140.7	140.7	140.7	145.3	154.1
Oil	1099.5	1087.5	1076.9	1086.6	1096.0	1106.8	1118.1	1185.8	1302.9	1491.2
Natural Gas	907.4	842.6	883.6	898.8	918.2	938.7	956.1	1012.1	1031.9	992.8
NGL-Gas Plant	57.9	56.8	58.5	59.2	60.2	61.1	62.1	66.0	69.5	72.5
Ethane	16.0	16.4	16.8	17.2	17.6	18.1	18.5	21.0	23.7	26.8
Coal	481.8	429.5	344.8	296.4	279.5	308.0	337.4	460.7	588.0	618.0
Renewables and Others	101.0	92.8	95.6	96.7	97.9	99.5	102.0	105.1	109.1	114.1

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

Manitoba

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	65.8	64.5	64.1	64.4	64.6	64.8	65.0	66.0	67.0	69.0
Commercial	43.8	42.5	44.7	45.0	45.2	45.4	45.7	47.2	48.8	51.1
Industrial	54.5	53.5	53.9	55.1	57.0	58.7	60.0	63.5	66.4	70.9
Transportation - Road	57.8	55.3	53.2	52.3	51.9	51.8	51.7	51.9	51.9	53.4
- Air, Rail, Marine	17.5	19.6	19.4	19.9	20.0	20.1	20.2	20.2	19.5	19.0
- Total	75.3	74.9	72.6	72.1	72.0	71.9	71.9	72.1	71.4	72.4
Non-Energy [a]	9.7	10.1	9.6	9.3	9.2	9.1	9.0	9.1	9.4	9.8
Total End Use	**249.1**	**245.4**	**245.0**	**245.9**	**247.9**	**249.9**	**251.6**	**258.0**	**263.0**	**273.2**
Own Use	35.1	33.5	35.1	37.6	39.0	39.7	40.3	40.8	42.3	41.5
Electricity and Steam Generation [b][d]	69.0	68.5	65.9	71.1	73.0	71.6	74.2	86.0	102.8	107.1
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Own Use and Conversions	**104.1**	**102.0**	**101.0**	**108.7**	**112.0**	**111.3**	**114.5**	**126.9**	**145.1**	**148.6**
Less Electricity, Steam, Coke and Coke Oven Gas	63.9	61.2	61.9	63.5	65.4	66.3	67.0	69.1	72.4	77.1
Primary Energy Demand	**289.4**	**286.2**	**284.1**	**291.1**	**294.5**	**294.9**	**299.1**	**315.7**	**335.7**	**344.8**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	62.5	63.9	65.4	70.1	72.0	70.7	73.4	85.2	102.0	106.3
Oil	99.1	99.2	96.3	95.5	95.2	94.9	94.8	95.5	95.8	98.1
Natural Gas	100.8	98.8	101.8	104.1	105.7	107.3	108.7	112.3	114.6	116.1
NGL-Gas Plant	4.0	3.9	4.0	4.0	4.1	4.2	4.3	4.7	5.0	5.4
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	8.0	6.1	2.2	2.6	2.6	2.6	2.5	2.6	2.7	2.7
Renewables and Others	14.9	14.3	14.5	14.7	14.9	15.1	15.3	15.5	15.8	16.2

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions
Saskatchewan

(Petajoules)

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	82.7	81.9	82.5	82.7	82.8	82.9	83.0	83.6	84.2	86.4
Commercial	39.3	39.0	40.1	40.1	40.1	40.2	40.4	41.6	43.0	44.9
Industrial	67.1	65.0	65.5	66.3	71.9	73.1	73.8	74.6	75.5	79.6
Transportation - Road	71.3	67.3	63.8	61.4	60.1	59.0	58.1	56.5	56.0	57.2
- Air, Rail, Marine	9.4	9.1	9.0	9.3	9.4	9.5	9.6	10.0	10.0	10.2
- Total	80.7	76.3	72.9	70.8	69.5	68.5	67.7	66.5	66.0	67.4
Non-Energy [a]	11.9	11.6	12.0	26.7	27.0	27.3	27.5	28.6	29.6	31.1
Total End Use	**281.7**	**273.8**	**273.0**	**286.6**	**291.4**	**292.0**	**292.4**	**294.9**	**298.3**	**309.3**
Own Use	51.9	54.0	56.1	59.0	59.6	60.5	61.3	63.4	65.6	64.8
Electricity and Steam Generation [b][d]	144.8	120.0	113.6	114.7	118.2	125.5	119.5	128.0	120.8	127.9
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Own Use and Conversions	**196.7**	**174.0**	**169.7**	**173.7**	**177.8**	**186.0**	**180.8**	**191.4**	**186.4**	**192.7**
Less Electricity, Steam, Coke and Coke Oven Gas	49.1	48.8	49.1	49.5	50.6	50.9	51.2	52.0	53.3	55.7
Primary Energy Demand	**429.3**	**399.0**	**393.5**	**410.8**	**418.6**	**427.1**	**422.0**	**434.3**	**431.5**	**446.3**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	10.2	15.2	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Oil	137.9	129.6	127.0	124.9	124.2	123.4	122.6	122.2	123.4	127.4
Natural Gas	141.9	143.5	144.7	163.2	165.3	167.1	168.6	172.8	176.3	178.9
NGL-Gas Plant	2.7	2.7	2.9	2.9	3.0	3.1	3.2	3.5	3.8	4.2
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	130.3	101.0	98.6	99.5	104.8	112.1	106.2	114.6	106.9	115.0
Renewables and Others	6.3	6.9	7.0	7.0	8.0	8.0	8.0	7.8	7.6	7.5

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions
Alberta

(Petajoules)

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	195.1	190.8	197.1	197.0	197.3	197.8	198.2	201.2	205.6	213.7
Commercial	122.1	119.9	129.7	132.0	133.8	135.3	136.9	143.0	150.3	157.1
Industrial	436.6	435.5	449.6	463.4	486.8	504.2	522.2	617.9	753.4	870.9
Transportation - Road	214.2	207.4	202.7	200.9	201.2	202.1	203.4	208.5	213.5	218.2
- Air, Rail, Marine	47.8	47.7	47.5	49.1	49.8	50.3	50.8	52.8	53.4	54.6
- Total	261.9	255.1	250.2	250.0	251.0	252.4	254.2	261.4	266.9	272.8
Non-Energy [a]	271.0	264.9	279.0	301.3	305.0	308.6	347.2	381.8	401.2	421.8
Total End Use	**1286.7**	**1266.2**	**1305.6**	**1343.6**	**1373.9**	**1398.3**	**1458.8**	**1605.2**	**1777.3**	**1936.3**
Own Use	81.5	80.0	80.7	82.3	83.2	84.2	85.2	88.9	93.0	95.2
Electricity and Steam Generation [b][d]	485.4	445.9	454.3	457.8	467.2	474.7	479.3	518.9	556.2	592.7
Other Conversions	13.7	22.8	24.2	26.0	26.4	27.0	27.7	29.6	31.9	31.9
Total Own Use and Conversions	**580.6**	**548.6**	**559.1**	**566.0**	**576.8**	**585.9**	**592.1**	**637.4**	**681.1**	**719.8**
Less Electricity, Steam, Coke and Coke Oven Gas	148.3	148.1	153.3	154.4	157.8	160.6	163.6	177.3	190.3	201.2
Primary Energy Demand	**1719.0**	**1666.7**	**1711.5**	**1755.3**	**1792.9**	**1823.6**	**1887.3**	**2065.4**	**2268.1**	**2454.9**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	5.8	7.4	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Oil	403.1	400.5	398.9	401.9	407.9	413.0	418.3	437.0	460.1	480.3
Natural Gas	746.0	722.5	722.8	740.0	764.2	786.2	809.1	918.4	985.0	1036.3
NGL-Gas Plant	37.3	37.0	37.7	56.8	56.9	57.0	57.0	56.8	56.7	56.7
Ethane	104.7	104.4	104.4	104.4	104.4	104.4	139.5	157.0	157.0	157.0
Coal	397.8	366.1	408.9	410.2	415.0	418.5	418.8	449.9	563.0	678.3
Renewables and Others	24.4	28.7	32.8	36.0	38.6	38.7	38.7	40.4	40.3	40.4

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-3 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions
British Columbia and Territories

(Petajoules)

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Sectoral Demand										
Residential	150.0	151.6	156.0	157.4	158.8	159.9	161.2	168.0	173.3	178.8
Commercial	92.2	94.4	97.4	97.7	98.2	99.1	100.1	105.2	110.7	116.4
Industrial	449.0	454.8	454.1	457.9	464.0	473.5	481.3	499.2	528.6	553.3
Transportation - Road	184.7	182.6	181.1	181.7	183.1	184.9	186.7	194.4	201.3	208.3
- Air, Rail, Marine	81.7	81.2	82.5	86.1	88.5	90.4	92.1	98.4	102.3	108.4
- Total	266.3	263.8	263.6	267.8	271.6	275.4	278.8	292.8	303.6	316.8
Non-Energy [a]	39.9	41.2	42.3	43.0	43.8	44.5	45.1	47.7	50.7	53.8
Total End Use	**997.4**	**1005.7**	**1013.4**	**1023.9**	**1036.4**	**1052.3**	**1066.5**	**1113.0**	**1166.8**	**1219.1**
Own Use	63.9	59.2	58.9	62.1	62.8	63.8	65.8	69.1	72.5	74.7
Electricity and Steam Generation [b][d]	230.4	224.2	219.0	223.5	226.2	226.3	224.5	238.0	263.3	288.6
Other Conversions	0.0	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3
Total Own Use and Conversions	**294.3**	**284.6**	**279.1**	**286.7**	**290.2**	**291.3**	**291.5**	**308.3**	**337.1**	**364.6**
Less Electricity, Steam, Coke and Coke Oven Gas	206.1	203.7	206.8	212.6	216.8	221.1	226.0	244.3	264.0	279.4
Primary Energy Demand	**1085.5**	**1086.5**	**1085.7**	**1098.0**	**1109.9**	**1122.6**	**1131.9**	**1177.1**	**1239.9**	**1304.3**
Primary Energy Demand by Fuel [c][d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	158.8	201.9	195.5	199.6	199.5	196.9	192.6	194.7	203.8	220.9
Oil	398.5	394.3	380.9	388.0	393.6	399.1	403.6	430.2	457.1	482.7
Natural Gas	292.2	256.3	277.8	278.9	282.8	287.9	293.0	304.2	327.4	344.1
NGL-Gas Plant	11.0	10.9	11.3	11.3	11.3	11.4	11.4	11.6	11.9	12.1
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	7.0	9.3	9.3	9.4	9.6	9.8	10.0	10.4	10.6	10.8
Renewables and Others	218.1	213.8	210.8	210.8	213.0	217.5	221.3	226.0	229.1	233.6

Notes: 1989 last year of actual data

[a] Includes Petrochemicals.

[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.

[c] Butanes for blending in gasoline is excluded from oil and included in NGL-Gas Plant at primary fuels level.

[d] Fuels used to generate electricity exports are not included

Table A4-4
End Use Demand by Fuel and Sector - Canada - Historical Data

(Petajoules)	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
Residential										
Electricity	147.0	157.8	169.1	182.5	196.4	215.7	233.3	257.7	278.9	313.8
Oil	592.8	625.4	621.0	653.3	616.6	648.1	619.1	607.1	546.9	529.1
Natural Gas	269.5	282.8	298.1	336.0	328.1	353.3	364.0	383.1	387.9	435.1
Propane and Butanes	32.8	32.5	38.5	40.0	36.8	42.0	38.2	31.8	31.3	18.3
Wood	72.5	68.7	62.6	56.6	57.3	58.4	62.6	64.9	60.4	68.5
Other	19.3	15.3	11.1	12.3	8.2	6.6	4.6	3.5	3.6	4.1
Total	**1133.9**	**1182.5**	**1200.4**	**1280.6**	**1243.3**	**1324.0**	**1321.8**	**1348.1**	**1309.0**	**1368.9**
Commercial										
Electricity	128.6	141.4	154.3	184.8	203.0	220.9	231.6	254.8	260.1	247.0
Oil	287.8	301.9	300.3	319.7	279.6	266.0	205.8	254.9	223.2	239.9
Natural Gas	166.3	175.5	199.2	241.2	227.8	255.9	259.3	277.7	295.8	312.4
Propane and Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	15.5	12.1	8.3	5.3	1.6	1.5	0.0	0.0	0.0	0.0
Total	**598.2**	**630.9**	**662.1**	**751.0**	**711.9**	**744.2**	**696.7**	**787.4**	**779.0**	**799.2**
Industrial										
Electricity	348.6	364.8	375.2	390.9	417.1	435.5	392.0	405.8	447.7	470.1
Oil	447.9	477.4	477.3	503.5	542.0	553.9	539.4	528.6	560.1	530.7
Natural Gas	388.7	420.9	477.4	515.7	556.4	613.5	584.7	598.7	651.4	658.0
Coal, Coke and Coke Oven Gas	277.5	276.6	232.1	227.8	247.8	241.7	228.2	237.8	232.3	241.6
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hog Fuel and Pulping Liquor	0.0	0.0	245.8	266.7	288.1	302.2	232.6	281.3	285.6	316.5
Propane and Butanes	22.6	21.0	24.6	27.7	29.6	40.2	35.4	29.9	30.3	20.8
Natural Gas for Bitumen	0.0	0.0	5.6	4.3	3.6	5.0	7.4	8.0	9.0	9.8
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1485.3**	**1560.7**	**1838.1**	**1936.5**	**2084.8**	**2192.0**	**2019.8**	**2090.2**	**2216.3**	**2247.5**
Non-Energy										
Asphalt	94.8	103.3	108.2	120.3	137.9	130.1	133.1	124.0	137.2	138.4
Lubes and Greases	30.4	30.6	32.8	34.3	38.3	39.4	37.2	38.8	38.4	40.3
Naphtha	13.4	12.8	13.1	16.1	23.1	15.8	14.8	14.8	16.8	15.7
Petroleum Coke	24.5	24.5	16.4	16.0	23.4	27.2	21.9	24.7	31.4	30.9
Natural Gas	26.7	34.8	37.3	37.7	40.8	42.9	49.9	59.6	83.9	88.1
Oil	45.6	78.1	75.8	79.9	81.5	82.0	68.4	84.0	96.3	137.2
Propane and Butanes	0.0	0.0	0.0	0.0	0.0	0.0	3.6	24.5	25.4	13.4
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	2.6	2.6
Other Oil	2.6	3.4	10.0	14.8	17.0	23.8	27.1	24.0	30.0	16.8
Total	**238.1**	**287.6**	**293.6**	**319.1**	**362.0**	**361.2**	**356.0**	**396.9**	**462.0**	**483.5**
Transportation										
Motor Gasoline	874.0	922.4	954.9	1021.6	1106.1	1147.1	1191.4	1220.5	1240.6	1283.4
Diesel Fuel Oil	154.7	157.3	166.8	181.2	200.8	224.6	214.6	261.2	288.1	293.3
Aviation Turbo - Total	86.4	94.9	98.0	103.4	118.4	130.5	138.2	137.1	138.1	143.7
Aviation Gasoline	8.7	7.7	7.5	7.7	8.0	7.8	7.8	7.8	7.9	8.3
Heavy Fuel Oil	72.2	79.3	81.6	88.8	93.9	81.9	66.7	63.9	61.6	68.1
Other	12.5	13.0	10.6	9.9	13.5	9.5	5.5	0.9	0.8	2.6
Total	**1208.4**	**1274.5**	**1319.5**	**1412.6**	**1540.7**	**1601.4**	**1624.3**	**1691.4**	**1737.2**	**1799.4**
Total End Use										
Electricity	624.2	664.0	698.7	758.2	816.5	872.0	856.9	918.3	986.7	1032.7
Oil	2739.8	2923.0	2968.3	3165.7	3295.3	3384.2	3289.7	3391.4	3416.7	3475.8
Natural Gas	851.2	914.0	1017.6	1134.9	1156.7	1270.6	1265.3	1327.1	1427.9	1503.4
Coal, Coke and Coke Oven Gas	320.7	313.0	257.4	250.0	262.5	253.3	234.3	242.2	236.6	246.6
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	72.5	68.7	62.6	56.6	57.3	58.4	62.6	64.9	60.4	68.5
Hog Fuel and Pulping Liquor	0.0	0.0	245.8	266.7	288.1	302.2	232.6	281.3	285.6	316.5
Other	55.4	53.5	63.2	67.7	66.4	82.1	77.3	88.8	89.6	55.2
Total	**4663.9**	**4936.2**	**5313.6**	**5699.9**	**5942.7**	**6222.9**	**6018.6**	**6314.0**	**6503.6**	**6698.5**

Table A4-4 (Continued)
End Use Demand by Fuel and Sector - Canada - Historical Data

(Petajoules)	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Residential										
Electricity	319.1	337.5	344.5	359.6	377.2	395.3	411.3	428.1	432.3	468.6
Oil	518.6	497.9	404.1	373.7	328.4	280.1	281.5	273.7	250.0	261.8
Natural Gas	447.9	458.6	463.7	520.2	505.0	524.5	562.9	525.1	498.2	549.9
Propane and Butanes	20.6	21.6	19.2	23.5	21.5	21.1	22.2	19.3	13.6	16.3
Wood	73.5	77.5	88.1	97.1	100.0	103.0	107.9	109.0	96.0	100.2
Other	4.2	3.4	4.0	4.0	3.2	5.5	6.2	6.1	5.6	4.9
Total	**1383.8**	**1396.5**	**1323.6**	**1378.1**	**1335.3**	**1329.5**	**1392.0**	**1361.4**	**1295.6**	**1401.7**
Commercial										
Electricity	261.9	257.4	268.3	276.4	287.8	294.9	304.4	325.9	342.6	368.9
Oil	210.5	202.6	192.3	172.1	161.0	145.9	107.7	103.8	99.2	106.3
Natural Gas	320.9	301.3	323.0	356.1	351.1	364.1	388.6	385.8	321.2	351.4
Propane and Butanes	14.6	15.0	15.6	19.2	17.1	16.4	17.9	14.6	16.0	18.2
Other	1.1	2.2	1.5	2.3	2.0	2.8	2.6	2.8	2.4	2.6
Total	**809.0**	**778.6**	**800.8**	**826.1**	**819.0**	**824.1**	**821.3**	**832.9**	**781.3**	**847.3**
Industrial										
Electricity	476.7	503.9	523.9	490.4	513.2	576.6	616.2	632.6	666.7	675.1
Oil	545.6	509.4	452.5	371.3	321.6	319.3	281.3	312.8	303.7	315.3
Natural Gas	693.7	686.8	646.6	596.8	601.8	683.1	722.3	724.0	781.3	857.4
Coal, Coke and Coke Oven Gas	250.0	248.3	226.4	205.2	216.4	240.1	245.8	236.6	234.8	244.3
Steam	43.2	42.0	45.2	62.2	49.9	45.8	33.3	31.6	27.2	16.0
Hog Fuel and Pulping Liquor	330.8	357.6	327.0	330.1	352.5	337.9	386.5	410.1	429.1	425.0
Propane and Butanes	24.7	24.0	24.0	24.1	25.0	25.6	31.2	28.6	21.3	26.8
Natural Gas for Bitumen	39.8	27.3	31.3	36.4	29.2	34.6	25.7	51.2	63.5	72.3
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**2404.4**	**2399.4**	**2276.9**	**2116.4**	**2109.6**	**2263.0**	**2342.3**	**2427.4**	**2527.6**	**2632.2**
Non-Energy										
Asphalt	146.5	140.0	128.3	108.3	112.0	105.3	119.7	122.7	133.5	120.9
Lubes and Greases	41.9	41.5	40.5	34.5	34.6	36.3	36.1	37.8	40.3	36.4
Naphtha	20.3	19.2	18.5	13.7	14.6	10.3	10.3	10.3	10.1	9.7
Petroleum Coke	25.9	34.3	35.9	24.8	27.4	31.4	28.1	40.1	43.2	39.8
Natural Gas	89.5	94.4	96.2	105.8	141.8	156.4	175.1	152.9	151.2	176.6
Oil	172.4	137.8	138.8	112.8	104.7	116.2	134.1	126.9	123.0	121.9
Propane and Butanes	19.9	17.2	16.8	11.4	17.7	22.1	27.6	15.6	27.2	39.0
Ethane	13.5	25.3	34.5	22.2	34.6	54.4	68.6	83.7	109.3	110.1
Other Oil	14.6	14.8	17.6	19.3	8.6	7.3	7.6	11.7	21.0	11.7
Total	**544.5**	**524.4**	**527.2**	**452.9**	**495.8**	**539.6**	**607.0**	**601.8**	**658.8**	**666.1**
Transportation										
Motor Gasoline	1328.0	1333.5	1290.3	1187.9	1150.6	1140.8	1134.5	1138.7	1151.6	1183.6
Diesel Fuel Oil	332.5	350.1	345.1	322.9	315.4	363.8	382.9	383.0	405.5	447.1
Aviation Turbo - Total	163.2	164.4	160.4	145.9	140.3	148.9	154.5	156.9	167.4	182.1
Aviation Gasoline	8.1	8.0	7.5	6.0	5.9	5.9	5.9	5.6	5.9	5.6
Heavy Fuel Oil	90.4	102.0	104.7	76.4	56.2	50.1	39.7	41.6	49.0	57.5
Other	4.0	3.8	4.2	5.7	9.5	15.3	17.0	21.7	31.9	32.6
Total	**1926.1**	**1961.8**	**1912.3**	**1744.7**	**1677.9**	**1724.9**	**1734.5**	**1747.5**	**1811.2**	**1908.4**
Total End Use										
Electricity	1059.3	1100.7	1139.2	1128.9	1181.1	1269.4	1334.7	1389.4	1444.4	1515.5
Oil	3618.5	3555.4	3336.5	2969.5	2781.2	2761.6	2723.8	2765.7	2803.3	2899.6
Natural Gas	1591.8	1568.4	1560.8	1615.3	1629.0	1762.9	1875.2	1840.3	1817.9	2010.0
Coal, Coke and Coke Oven Gas	255.2	252.8	231.4	210.6	220.8	244.5	250.6	241.2	238.8	247.6
Steam	43.8	43.1	45.7	63.2	50.6	46.4	34.0	32.2	27.6	16.4
Wood	73.5	77.5	88.1	97.1	100.0	103.0	107.9	109.0	96.0	100.2
Hog Fuel and Pulping Liquor	330.8	357.6	327.0	330.1	352.5	337.9	386.5	410.1	429.1	425.0
Other	94.9	105.1	111.9	103.5	122.4	155.1	184.4	182.9	217.6	241.4
Total	**7067.9**	**7060.8**	**6840.7**	**6518.2**	**6437.6**	**6681.0**	**6897.0**	**6970.9**	**7074.6**	**7455.6**

Table A4-5
End Use Demand by Fuel and Sector - Canada

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	503.2	501.0	515.8	522.7	529.8	536.0	541.5	571.2	608.6	647.2
Oil	284.8	280.2	284.7	278.6	272.4	266.2	260.1	235.7	219.0	206.3
Natural Gas	583.5	566.3	598.8	601.8	605.1	609.0	613.2	634.5	647.1	663.7
Propane and Butanes	21.3	20.4	21.1	21.2	21.3	21.4	21.5	22.0	22.7	23.5
Wood	94.4	94.2	97.0	97.1	97.2	97.3	97.4	98.4	99.6	101.1
Other	4.4	3.9	3.9	3.9	3.8	3.7	3.7	3.4	3.1	2.9
Total	**1491.6**	**1466.0**	**1521.4**	**1525.2**	**1529.7**	**1533.6**	**1537.3**	**1565.1**	**1600.1**	**1644.7**
Commercial										
Electricity	382.1	381.0	396.4	402.0	405.6	410.7	416.7	445.8	477.2	509.7
Oil	108.7	106.9	108.5	108.6	108.1	107.7	107.5	106.7	105.4	103.7
Natural Gas	372.6	367.1	384.5	388.2	390.3	393.7	397.8	416.8	437.1	457.1
Propane and Butanes	23.9	23.0	23.8	23.9	23.9	23.9	24.0	24.3	24.6	24.8
Other	2.2	2.2	2.3	2.3	2.4	2.4	2.4	3.0	3.7	4.5
Total	**889.4**	**880.1**	**915.5**	**925.0**	**930.2**	**938.4**	**948.4**	**996.6**	**1048.0**	**1100.0**
Industrial										
Electricity	661.6	660.3	673.6	690.4	715.5	742.9	766.8	846.6	929.4	1023.4
Oil	326.6	325.8	317.6	325.2	337.0	352.2	362.8	428.8	542.3	723.6
Natural Gas	869.6	844.2	869.6	885.4	921.1	948.6	974.1	1006.8	1003.4	947.2
Coal, Coke and Coke Oven Gas	234.3	228.3	235.0	241.2	252.4	265.9	275.3	291.1	307.0	324.8
Steam	24.0	23.1	23.3	23.9	24.9	25.7	26.4	27.8	29.4	31.8
Hog Fuel and Pulping Liquor	411.1	411.3	407.7	409.3	412.4	416.5	420.0	419.4	421.8	427.8
Propane and Butanes	28.3	27.4	27.5	27.8	28.6	29.5	30.1	31.3	33.1	35.4
Natural Gas for Bitumen	73.2	76.9	80.1	83.4	86.6	89.8	93.0	149.0	160.0	170.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	88.0	170.0
Other	0.0	0.0	0.2	0.5	0.8	1.1	1.8	6.9	10.4	14.1
Total	**2628.9**	**2597.3**	**2634.7**	**2687.1**	**2779.2**	**2872.2**	**2950.3**	**3207.6**	**3524.8**	**3868.2**
Non-Energy										
Asphalt	129.2	133.0	135.7	137.7	141.5	145.3	148.8	163.6	181.1	200.6
Lubes and Greases	36.6	38.0	38.4	38.8	39.4	40.1	40.9	45.2	49.9	55.3
Naphtha	9.2	9.1	9.2	9.4	9.5	9.7	10.0	11.2	12.5	14.0
Petroleum Coke	30.6	31.4	32.1	32.9	33.6	34.4	35.3	39.6	44.6	50.2
Natural Gas	171.8	145.8	158.5	175.3	177.7	180.2	182.7	196.2	211.0	227.4
Oil	120.5	121.5	123.7	125.8	128.0	130.2	132.5	144.6	158.0	172.8
Propane and Butanes	30.2	30.6	31.2	51.0	51.6	52.3	53.0	56.8	61.1	65.9
Ethane	120.7	120.8	121.2	121.6	122.1	122.5	158.1	178.0	180.8	183.9
Other Oil	18.0	18.2	18.4	18.7	18.9	19.1	19.4	20.7	22.1	23.7
Total	**666.9**	**648.4**	**668.3**	**711.1**	**722.4**	**734.0**	**780.7**	**856.0**	**921.1**	**993.7**
Transportation										
Motor Gasoline	1206.2	1178.8	1160.9	1159.7	1159.7	1161.8	1165.5	1189.6	1214.1	1235.9
Diesel Fuel Oil	459.6	459.5	461.0	469.7	477.6	484.9	491.7	518.6	538.4	559.8
Aviation Turbo - Total	186.6	179.1	180.5	187.4	191.5	194.5	197.2	211.6	222.3	238.4
Aviation Gasoline	5.4	5.5	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Heavy Fuel Oil	60.4	62.1	63.9	67.1	69.4	71.3	72.7	75.8	76.2	78.6
Other	31.7	32.2	33.9	35.6	37.3	38.9	40.6	49.0	57.5	65.9
Total	**1950.0**	**1917.2**	**1905.6**	**1924.9**	**1940.9**	**1956.8**	**1973.1**	**2050.0**	**2113.8**	**2184.0**
Total End Use										
Electricity	1550.0	1545.4	1589.1	1618.7	1654.8	1693.7	1729.4	1869.4	2022.4	2189.0
Oil	2982.6	2949.1	2940.1	2965.0	2992.1	3023.0	3049.7	3197.0	3391.2	3668.2
Natural Gas	2073.0	2002.5	2094.4	2137.7	2185.3	2226.5	2266.9	2413.3	2472.6	2483.5
Coal, Coke and Coke Oven Gas	236.7	230.3	237.0	243.1	254.2	267.7	277.0	292.3	396.0	495.6
Steam	24.4	23.4	23.6	24.1	25.0	25.8	26.4	27.8	29.4	31.8
Wood	94.4	94.2	97.0	97.1	97.2	97.3	97.4	98.4	99.6	101.1
Hog Fuel and Pulping Liquor	411.1	411.3	407.7	409.3	412.4	416.5	420.0	419.4	421.8	427.8
Other	254.6	252.8	256.7	278.3	281.3	284.4	323.0	357.6	374.7	393.6
Total	**7626.8**	**7509.0**	**7645.5**	**7773.3**	**7902.4**	**8034.9**	**8189.8**	**8675.2**	**9207.8**	**9790.6**

Note: 1989 is last year of actual data.

Table A4-5 (Continued)
End Use Demand by Fuel and Sector - Atlantic

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	39.1	40.4	41.2	41.8	42.4	43.0	43.6	46.7	49.6	52 5
Oil	53.8	54.8	55.3	54.8	54.2	53.8	53.3	51.0	49.0	47.4
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane and Butanes	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7
Wood	23.1	23.5	23.7	23.7	23.7	23.6	23.6	23.6	23 6	23.6
Other	1.2	0.9	0.9	0.9	0.8	0.8	0.8	0.6	0.5	0.4
Total	**118.8**	**121.2**	**122.7**	**122.7**	**122.7**	**122.8**	**123.0**	**123.6**	**124.3**	**125.6**
Commercial										
Electricity	24.4	25.2	26.0	26.7	27.3	27.8	28.2	30.4	32.7	34.9
Oil	34.5	34.3	34.4	34.8	35.0	35.1	35.1	35.2	35.4	35.5
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0
Propane and Butanes	2.6	2.7	2.8	2.8	2.8	2.9	2.9	3.0	3.2	3.3
Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Total	**61.9**	**62.7**	**63.5**	**64.7**	**65.5**	**66.1**	**66.6**	**69.0**	**71.7**	**74.3**
Industrial										
Electricity	48.3	50.0	51.4	52.4	54.0	56.2	57.5	68.0	71.1	71.9
Oil	49.3	44.4	44.7	44.3	45.0	45.8	46.1	51.5	55.2	55 9
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	7.1	6.9	7.1	7.3	7.7	8.0	8.3	8.4	9.1	10.1
Steam	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.2
Hog Fuel and Pulping Liquor	46.6	44.7	44.4	44.3	43.9	43.7	43.7	40.5	40.1	41.2
Propane and Butanes	2.0	1.9	2.0	2.0	2.0	2.1	2.1	2.1	2.2	2.3
Natural Gas for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.9	1.2
Total	**154.2**	**148.7**	**150.5**	**151.3**	**153.6**	**156.8**	**158.8**	**171.7**	**179.7**	**183.9**
Non-Energy										
Asphalt	12.8	12.7	13.6	14.1	14.7	15.1	15.4	17.1	18.7	20.1
Lubes and Greases	2.4	2.5	2.5	2.5	2.6	2.6	2.6	2.9	3.1	3.3
Naphtha	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Petroleum Coke	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Propane and Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**20.6**	**20.6**	**21.5**	**22.0**	**22.6**	**23.1**	**23.5**	**25.4**	**27.2**	**28.9**
Transportation										
Motor Gasoline	99.3	97.3	96.3	96.4	96.7	96.9	97.2	98.1	99.1	100 0
Diesel Fuel Oil	48.9	49.7	50.5	52.0	53.2	54.2	55.1	58.6	60.5	62.9
Aviation Turbo-Total	20.3	21.0	21.1	21.9	22.3	22.6	22.8	24.2	25.0	26.5
Aviation Gasoline	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Heavy Fuel Oil	11.5	10.2	10.7	11.4	11.9	12.4	12.9	14.4	15.5	17.0
Other	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.6	0.7	0 9
Total	**180.5**	**178.8**	**179.1**	**182.2**	**184.7**	**186.8**	**188.6**	**196.1**	**201.1**	**207.6**
Total End Use										
Electricity	111.8	115.6	118.6	120.8	123.7	127.0	129.4	145.1	153 4	159 4
Oil	338.5	332.7	334.7	337.8	341.3	344 2	346.2	358.7	367.2	374 4
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0 0
Coal, Coke and Coke Oven Gas	8.5	7.9	8.1	8.3	8.6	8.9	9.2	9.0	9 5	10 5
Steam	0.9	0 9	0.9	1.0	1.0	1.0	1.0	1 0	1.1	1 2
Wood	23.1	23.5	23 7	23.7	23 7	23 6	23.6	23.6	23 6	23 6
Hog Fuel and Pulping Liquor	46.6	44.7	44.4	44.3	43.9	43.7	43.7	40.5	40 1	41 2
Other	6.6	6.7	6.9	7.0	7.2	7.3	7.4	7.8	9.1	9 9
Total	**536.0**	**532.0**	**537.3**	**542.9**	**549.2**	**555.7**	**560.4**	**585.8**	**604.0**	**620.3**

Note: 1989 is last year of actual data.

Table A4-5 (Continued)
End Use Demand by Fuel and Sector - Quebec

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	184.4	181.3	189.1	192.0	195.1	198.2	201.1	215.9	230.4	245.2
Oil	82.1	78.9	80.0	76.8	73.6	70.5	67.2	54.5	45.2	37.6
Natural Gas	23.9	25.4	26.5	26.1	25.8	25.5	25.3	24.4	22.6	20.9
Propane and Butanes	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.4	3.5	3.6
Wood	33.0	32.3	33.4	33.4	33.4	33.5	33.5	33.8	34.2	34.9
Other	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**327.1**	**321.3**	**332.7**	**332.0**	**331.7**	**331.4**	**330.8**	**332.3**	**336.4**	**342.6**
Commercial										
Electricity	107.7	105.9	106.7	108.1	109.5	111.3	113.2	122.0	130.7	139.8
Oil	27.5	26.6	26.6	26.3	26.0	25.7	25.5	25.2	24.7	24.3
Natural Gas	50.2	55.2	55.5	55.8	56.0	56.3	56.7	58.6	60.1	61.0
Propane and Butanes	3.2	3.1	3.1	3.1	3.1	3.2	3.2	3.3	3.4	3.4
Other	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.8	1.0	1.2
Total	**189.0**	**191.3**	**192.3**	**193.9**	**195.2**	**197.0**	**199.3**	**209.8**	**219.9**	**229.7**
Industrial										
Electricity	247.3	243.1	247.2	253.1	261.2	270.6	278.5	304.1	334.7	371.5
Oil	84.8	88.3	91.7	94.3	98.2	106.2	110.9	134.3	165.8	203.3
Natural Gas	128.5	134.3	132.7	134.9	138.4	138.3	140.1	129.3	111.0	93.8
Coal, Coke and Coke Oven Gas	27.3	27.3	27.8	28.7	29.9	31.1	32.0	33.8	35.8	37.7
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hog Fuel and Pulping Liquor	71.4	71.9	71.3	71.1	70.6	71.0	71.4	70.5	69.8	69.3
Propane and Butanes	3.4	3.4	3.4	3.5	3.6	3.6	3.7	3.8	3.8	4.0
Natural Gas for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.1	0.1	0.2	0.3	0.4	3.8	4.5	5.4
Total	**562.6**	**568.4**	**574.3**	**585.7**	**602.1**	**621.2**	**636.9**	**679.6**	**725.5**	**785.0**
Non-Energy										
Asphalt	32.8	33.3	34.9	36.1	37.5	38.9	40.1	44.6	49.3	54.8
Lubes and Greases	6.1	6.3	6.2	6.1	6.1	6.2	6.3	6.8	7.5	8.3
Naphtha	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.2	1.4	1.5
Petroleum Coke	19.3	19.8	20.2	20.8	21.3	21.8	22.4	25.3	28.6	32.4
Natural Gas	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Oil	15.5	15.7	16.0	16.3	16.6	17.0	17.3	19.1	21.1	23.3
Propane and Butanes	7.0	7.0	7.1	7.3	7.4	7.6	7.7	8.5	9.4	10.4
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	6.2	6.4	6.5	6.7	6.9	7.0	7.2	8.2	9.2	10.5
Total	**88.7**	**90.2**	**92.7**	**95.1**	**97.7**	**100.3**	**102.8**	**114.4**	**127.3**	**141.9**
Transportation										
Motor Gasoline	257.6	251.5	248.4	248.5	248.9	249.5	250.7	256.0	259.1	262.2
Diesel Fuel Oil	95.7	94.5	95.1	96.8	98.3	99.6	100.8	105.2	109.2	113.5
Aviation Turbo-Total	37.3	34.0	34.3	35.7	36.6	37.2	37.8	41.0	43.5	47.1
Aviation Gasoline	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Heavy Fuel Oil	18.4	19.8	20.2	20.9	21.4	21.7	21.8	21.4	20.1	19.3
Other	2.7	2.9	3.3	3.7	4.2	4.6	5.0	7.2	9.4	11.5
Total	**412.4**	**403.5**	**402.1**	**406.5**	**410.1**	**413.4**	**417.0**	**431.6**	**442.1**	**454.4**
Total End Use										
Electricity	540.6	531.3	544.2	554.6	567.3	581.6	594.4	644.1	698.3	759.6
Oil	685.1	676.9	681.9	687.2	693.3	703.2	709.9	743.5	785.6	838.7
Natural Gas	203.6	216.0	215.9	218.2	221.8	221.9	224.1	215.2	197.6	180.4
Coal, Coke and Coke Oven Gas	27.3	27.3	27.8	28.7	29.9	31.1	32.0	33.8	35.8	37.7
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	33.0	32.3	33.4	33.4	33.4	33.5	33.5	33.8	34.2	34.9
Hog Fuel and Pulping Liquor	71.4	71.9	71.3	71.1	70.6	71.0	71.4	70.5	69.8	69.3
Other	18.9	19.0	19.5	20.0	20.5	21.0	21.5	26.9	29.8	32.9
Total	**1579.9**	**1574.7**	**1594.2**	**1613.2**	**1636.8**	**1663.3**	**1686.8**	**1767.8**	**1851.1**	**1953.5**

Note: 1989 is last year of actual data.

Table A4-5 (Continued)
End Use Demand by Fuel and Sector - Ontario

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	170.5	169.4	175.3	177.9	180.4	182.4	183.8	192.2	206.6	219.7
Oil	72.9	73.1	75.4	72.8	70.5	68.4	66.4	58.4	52.7	48.5
Natural Gas	278.1	261.8	283.5	286.1	288.4	290.8	293.4	306.4	315.9	325.5
Propane and Butanes	7.2	6.6	7.0	7.1	7.1	7.1	7.2	7.4	7.8	8.1
Wood	22.8	23.1	24.3	24.4	24.5	24.5	24.6	25.0	25.6	26.2
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**552.2**	**534.7**	**566.3**	**569.0**	**571.7**	**574.0**	**576.1**	**590.3**	**609.3**	**628.6**
Commercial										
Electricity	145.2	144.3	152.4	154.6	155.2	156.9	159.1	170.9	184.3	197.9
Oil	24.3	24.5	25.4	25.3	25.0	24.9	24.9	24.4	23.4	22.2
Natural Gas	163.2	153.7	161.6	163.2	163.6	165.0	167.0	176.4	186.3	196.2
Propane and Butanes	7.5	6.8	7.1	7.2	7.1	7.1	7.1	7.3	7.4	7.5
Other	1.1	1.1	1.2	1.3	1.3	1.4	1.5	1.9	2.3	2.8
Total	**341.2**	**330.4**	**347.7**	**351.6**	**352.2**	**355.3**	**359.5**	**380.8**	**403.8**	**426.5**
Industrial										
Electricity	170.3	169.3	172.5	177.5	185.0	194.1	202.8	220.0	243.3	281.7
Oil	79.7	78.9	78.7	80.2	82.9	86.0	89.1	109.1	164.5	290.2
Natural Gas	362.1	341.0	347.5	355.7	370.4	385.1	395.8	424.7	422.4	365.2
Coal, Coke and Coke Oven Gas	188.8	183.4	189.4	194.3	203.7	215.5	223.5	237.0	250.1	264.6
Steam	23.0	22.1	22.3	22.9	23.8	24.6	25.3	26.7	28.2	30.5
Hog Fuel and Pulping Liquor	69.3	66.1	65.6	65.8	66.3	67.2	67.9	68.8	69.9	71.6
Propane and Butanes	11.4	10.8	10.8	10.9	11.2	11.5	11.8	12.3	12.9	14.0
Natural Gas for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.1	0.3	0.4	0.6	1.2	2.7	4.4	6.7
Total	**904.7**	**871.5**	**886.9**	**907.4**	**943.7**	**984.7**	**1017.3**	**1101.2**	**1195.8**	**1324.7**
Non-Energy										
Asphalt	37.9	38.5	36.8	36.0	36.1	36.6	37.3	41.2	46.4	52.7
Lubes and Greases	16.7	17.4	17.5	17.8	18.1	18.5	18.9	21.2	23.8	26.9
Naphtha	6.3	6.1	6.2	6.3	6.4	6.6	6.7	7.6	8.6	9.7
Petroleum Coke	1.9	1.9	2.0	2.0	2.1	2.1	2.2	2.5	2.8	3.2
Natural Gas	32.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
Oil	88.9	89.8	91.6	93.4	95.3	97.2	99.1	109.5	120.9	133.4
Propane and Butanes	19.7	20.1	20.6	21.2	21.7	22.2	22.8	25.8	29.2	33.0
Ethane	16.0	16.4	16.8	17.2	17.6	18.1	18.5	21.0	23.7	26.8
Other Oil	4.7	4.8	4.8	4.9	4.9	5.0	5.0	5.3	5.5	5.8
Total	**225.1**	**209.9**	**211.3**	**213.6**	**217.1**	**221.1**	**225.5**	**248.9**	**275.7**	**306.4**
Transportation										
Motor Gasoline	450.9	445.5	443.0	447.1	448.7	450.9	453.5	470.0	487.4	498.9
Diesel Fuel Oil	136.1	137.2	138.1	140.9	143.0	145.0	146.8	155.3	163.0	171.2
Aviation Turbo - Total	57.7	52.9	53.5	55.7	57.1	58.2	59.2	64.5	68.9	75.1
Aviation Gasoline	1.3	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6
Heavy Fuel Oil	13.9	14.6	15.1	15.9	16.5	17.0	17.4	18.3	18.6	19.4
Other	12.9	13.2	13.8	14.5	15.1	15.8	16.5	19.8	23.1	26.4
Total	**672.8**	**664.8**	**665.0**	**675.6**	**682.0**	**688.4**	**694.9**	**729.5**	**762.7**	**792.7**
Total End Use										
Electricity	487.3	484.4	501.7	511.6	522.4	535.3	547.7	586.1	637.9	703.8
Oil	993.2	986.6	989.6	999.8	1008.2	1017.9	1028.1	1088.8	1188.0	1358.8
Natural Gas	836.7	771.8	808.2	820.8	838.5	857.3	872.8	925.5	943.9	907.4
Coal, Coke and Coke Oven Gas	188.8	183.4	189.4	194.3	203.7	215.5	223.5	237.0	250.1	264.6
Steam	23.0	22.1	22.3	22.9	23.8	24.6	25.3	26.7	28.2	30.6
Wood	22.8	23.1	24.3	24.4	24.5	24.5	24.6	25.0	25.6	26.2
Hog Fuel and Pulping Liquor	69.3	66.1	65.6	65.8	66.3	67.2	67.9	68.8	69.9	71.6
Other	74.8	73.9	76.0	77.6	79.3	81.2	83.4	92.9	103.5	115.9
Total	**2695.9**	**2611.3**	**2677.1**	**2717.1**	**2766.7**	**2823.5**	**2873.3**	**3050.6**	**3247.2**	**3478.9**

Note: 1989 is last year of actual data.

Table A4-5 (Continued)
End Use Demand by Fuel and Sector - Manitoba

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	23.6	23.5	23.1	23.3	23.4	23.6	23.7	24.5	25.3	26.7
Oil	11.3	11.2	11.3	11.3	11.3	11.3	11.2	11.2	11.4	11.6
Natural Gas	26.8	25.8	25.8	25.9	25.9	26.0	26.1	26.4	26.3	26.6
Propane and Butanes	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3
Wood	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**65.8**	**64.5**	**64.1**	**64.4**	**64.6**	**64.8**	**65.0**	**66.0**	**67.0**	**69.0**
Commercial										
Electricity	13.6	13.5	14.3	14.4	14.6	14.7	14.9	15.4	16.0	16.9
Oil	2.3	2.2	2.3	2.3	2.3	2.3	2.3	2.2	2.2	2.3
Natural Gas	26.8	25.8	27.2	27.4	27.5	27.6	27.8	28.8	29.7	31.1
Propane and Butanes	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8
Other	0.3	0.3	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0
Total	**43.8**	**42.5**	**44.7**	**45.0**	**45.2**	**45.4**	**45.7**	**47.2**	**48.8**	**51.1**
Industrial										
Electricity	16.4	16.3	16.6	17.0	17.6	18.2	18.7	20.4	22.2	24.6
Oil	5.4	5.7	5.8	5.8	5.9	5.9	5.9	6.7	7.4	8.4
Natural Gas	17.3	16.7	16.7	17.2	18.1	18.9	19.5	20.1	20.0	20.6
Coal, Coke and Coke Oven Gas	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.6	2.7	2.7
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hog Fuel and Pulping Liquor	11.8	11.2	11.3	11.4	11.6	11.8	11.9	12.1	12.4	12.7
Propane and Butanes	1.2	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.6	1.7
Natural Gas for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2
Total	**54.5**	**53.5**	**53.9**	**55.1**	**57.0**	**58.7**	**60.0**	**63.5**	**66.4**	**70.9**
Non-Energy										
Asphalt	3.3	3.6	3.2	3.0	2.8	2.7	2.7	2.7	2.9	3.2
Lubes and Greases	1.3	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.5
Naphtha	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Petroleum Coke	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane and Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**9.7**	**10.1**	**9.6**	**9.3**	**9.2**	**9.1**	**9.0**	**9.1**	**9.4**	**9.8**
Transportation										
Motor Gasoline	47.6	45.1	43.0	42.0	41.6	41.3	41.1	40.2	39.3	40.0
Diesel Fuel Oil	20.0	21.0	20.8	21.1	21.3	21.5	21.7	22.7	23.0	23.3
Aviation Turbo - Total	6.4	7.5	7.4	7.6	7.6	7.6	7.6	7.4	7.0	6.6
Aviation Gasoline	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.7	0.8	0.8	0.9	0.9	1.0	1.1	1.4	1.7	1.9
Total	**75.3**	**74.9**	**72.6**	**72.1**	**72.0**	**71.9**	**71.9**	**72.1**	**71.4**	**72.4**
Total End Use										
Electricity	53.6	53.2	53.9	54.7	55.6	56.5	57.3	60.3	63.6	68.2
Oil	98.5	98.6	96.0	95.2	94.9	94.7	94.5	95.2	95.5	97.8
Natural Gas	75.7	73.1	74.4	75.3	76.4	77.4	78.2	80.2	81.1	83.4
Coal, Coke and Coke Oven Gas	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.6	2.7	2.7
Steam	0.4	0.3	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0
Wood	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Hog Fuel and Pulping Liquor	11.8	11.2	11.3	11.4	11.6	11.8	11.9	12.1	12.4	12.7
Other	4.2	4.1	4.2	4.3	4.4	4.5	4.6	5.0	5.3	5.8
Total	**249.1**	**245.4**	**245.0**	**245.9**	**247.9**	**249.9**	**251.6**	**258.0**	**263.0**	**273.2**

Note: 1989 is last year of actual data.

Table A4-5 (Continued)
End Use Demand by Fuel and Sector - Saskatchewan

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	14.6	14.2	14.0	14.0	14.1	14.1	14.1	14.3	14.6	15.2
Oil	26.6	25.4	25.6	25.7	25.7	25.6	25.5	25.2	25.4	25.8
Natural Gas	38.8	39.0	39.7	39.7	39.8	40.0	40.1	40.9	41.0	42.1
Propane and Butanes	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Wood	1.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.7
Other	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
Total	**82.7**	**81.9**	**82.5**	**82.7**	**82.8**	**82.9**	**83.0**	**83.6**	**84.2**	**86.4**
Commercial										
Electricity	13.5	13.2	13.6	13.6	13.6	13.6	13.7	14.2	14.7	15.4
Oil	1.7	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Natural Gas	23.0	23.2	23.8	23.8	23.9	23.9	24.0	24.8	25.6	26.7
Propane and Butanes	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**39.3**	**39.0**	**40.1**	**40.1**	**40.1**	**40.2**	**40.4**	**41.6**	**43.0**	**44.9**
Industrial										
Electricity	12.7	12.5	12.7	13.0	14.2	14.4	14.6	14.9	15.5	16.8
Oil	10.1	8.3	8.6	8.5	8.7	8.8	8.8	9.1	9.7	10.5
Natural Gas	36.1	36.3	36.4	37.0	40.0	40.6	41.1	41.3	41.1	43.1
Coal, Coke and Coke Oven Gas	3.9	3.6	3.6	3.7	3.8	3.8	3.9	4.0	4.0	4.0
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hog Fuel and Pulping Liquor	3.3	3.1	3.1	3.1	4.2	4.2	4.2	4.0	3.8	3.6
Propane and Butanes	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.3	1.4
Natural Gas for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Total	**67.1**	**65.0**	**65.5**	**66.3**	**71.9**	**73.1**	**73.8**	**74.6**	**75.5**	**79.6**
Non-Energy										
Asphalt	9.2	8.7	9.1	9.2	9.5	9.7	9.9	10.6	11.3	12.4
Lubes and Greases	1.6	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.3	2.5
Naphtha	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Petroleum Coke	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.3	1.4	1.6
Natural Gas	0.0	0.0	0.0	14.4	14.4	14.4	14.4	14.4	14.4	14.4
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Propane and Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**11.9**	**11.6**	**12.0**	**26.7**	**27.0**	**27.3**	**27.5**	**28.6**	**29.6**	**31.1**
Transportation										
Motor Gasoline	59.7	55.9	52.5	49.9	48.3	46.9	45.7	42.5	41.0	41.6
Diesel Fuel Oil	16.7	16.5	16.3	16.6	17.0	17.3	17.7	19.3	20.1	20.6
Aviation Turbo - Total	3.3	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1.2	1.5	1.8
Total	**80.7**	**76.3**	**72.9**	**70.8**	**69.5**	**68.5**	**67.7**	**66.5**	**66.0**	**67.4**
Total End Use										
Electricity	40.8	39.9	40.2	40.6	41.8	42.1	42.4	43.4	44.9	47.4
Oil	130.3	122.5	120.0	118.0	117.3	116.5	115.8	115.4	116.4	120.3
Natural Gas	97.9	98.5	99.9	115.0	118.1	119.0	119.7	121.4	122.2	126.6
Coal, Coke and Coke Oven Gas	4.0	3.7	3.7	3.8	3.8	3.9	4.0	4.0	4.0	4.1
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	1.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.7
Hog Fuel and Pulping Liquor	3.3	3.1	3.1	3.1	4.2	4.2	4.2	4.0	3.8	3.6
Other	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.9	5.3	5.7
Total	**281.7**	**273.8**	**273.0**	**286.6**	**291.4**	**292.0**	**292.4**	**294.9**	**298.3**	**309.3**

Note: 1989 is last year of actual data.

Table A4-5 (Continued)
End Use Demand by Fuel and Sector - Alberta

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	26.8	27.0	27.1	27.2	27.3	27.4	27.5	28.1	29.6	31.6
Oil	20.9	20.8	20.9	21.0	21.0	21.0	20.9	21.0	21.6	22.4
Natural Gas	139.2	135.0	140.9	140.7	140.9	141.3	141.8	144.1	146.4	151.5
Propane and Butanes	4.9	4.8	5.0	5.0	5.0	5.0	5.0	5.1	5.2	5.5
Wood	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Other	1.0	0.9	0.9	0.9	0.9	0.9	0.8	0.7	0.6	0.5
Total	**195.1**	**190.8**	**197.1**	**197.0**	**197.3**	**197.8**	**198.2**	**201.2**	**205.6**	**213.7**
Commercial										
Electricity	37.8	38.1	41.3	42.0	42.6	43.1	43.7	45.9	48.6	51.2
Oil	3.4	3.4	3.7	3.7	3.7	3.8	3.8	3.9	4.1	4.2
Natural Gas	76.2	73.9	79.9	81.4	82.5	83.5	84.5	88.3	92.8	97.0
Propane and Butanes	4.6	4.5	4.8	4.9	4.9	4.9	4.9	4.8	4.8	4.7
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**122.1**	**119.9**	**129.7**	**132.0**	**133.8**	**135.3**	**136.9**	**143.0**	**150.3**	**157.1**
Industrial										
Electricity	67.3	67.8	69.8	70.3	73.1	75.5	78.1	89.5	98.6	105.2
Oil	44.7	47.0	48.1	50.0	53.0	55.0	57.0	62.8	72.6	79.6
Natural Gas	229.3	217.2	223.0	229.0	241.2	250.6	260.6	282.2	299.6	311.5
Coal, Coke and Coke Oven Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Hog Fuel and Pulping Liquor	15.6	20.2	22.1	24.2	26.2	26.3	26.3	26.8	26.2	25.7
Propane and Butanes	6.5	6.3	6.4	6.5	6.8	7.0	7.2	7.6	8.3	8.9
Natural Gas for Bitumen	73.2	76.9	80.1	83.4	86.6	89.8	93.0	149.0	160.0	170.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	88.0	170.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**436.6**	**435.5**	**449.6**	**463.4**	**486.8**	**504.2**	**522.2**	**617.9**	**753.4**	**870.9**
Non-Energy										
Asphalt	22.8	24.6	25.7	26.3	27.3	28.1	28.8	31.2	34.4	37.3
Lubes and Greases	4.1	4.3	4.5	4.6	4.7	4.9	5.0	5.4	5.9	6.3
Naphtha	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.1
Petroleum Coke	4.3	4.5	4.6	4.7	4.8	4.9	5.0	5.7	6.4	7.3
Natural Gas	114.7	106.7	119.4	121.8	124.2	126.7	129.2	142.7	157.5	173.9
Oil	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Propane and Butanes	3.4	3.4	3.4	22.5	22.5	22.5	22.5	22.5	22.5	22.5
Ethane	104.7	104.4	104.4	104.4	104.4	104.4	139.5	157.0	157.0	157.0
Other Oil	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.5	6.5
Total	**271.0**	**264.9**	**279.0**	**301.3**	**305.0**	**308.6**	**347.2**	**381.8**	**401.2**	**421.8**
Transportation										
Motor Gasoline	158.5	153.0	148.6	146.6	145.8	145.7	146.0	147.8	150.0	152.0
Diesel Fuel Oil	69.9	69.1	68.4	69.3	70.5	71.7	72.9	76.6	78.9	81.3
Aviation Turbo - Total	24.7	24.2	24.3	25.0	25.4	25.6	25.8	26.6	26.8	27.6
Aviation Gasoline	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
Heavy Fuel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	8.3	8.3	8.5	8.6	8.8	8.9	9.1	9.9	10.7	11.5
Total	**261.9**	**255.1**	**250.2**	**250.0**	**251.0**	**252.4**	**254.2**	**261.4**	**266.9**	**272.8**
Total End Use										
Electricity	132.1	133.2	138.4	139.7	143.3	146.3	149.5	163.8	177.3	188.6
Oil	370.7	368.3	366.1	368.6	373.8	378.2	382.7	398.8	418.5	435.8
Natural Gas	633.5	610.5	644.2	657.1	676.5	693.1	710.4	808.1	858.7	906.9
Coal, Coke and Coke Oven Gas	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.6	88.5	170.4
Steam	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Hog Fuel and Pulping Liquor	15.6	20.2	22.1	24.2	26.2	26.3	26.3	26.8	26.2	25.7
Other	131.6	131.0	131.6	150.9	151.2	151.5	186.8	204.9	205.9	206.7
Total	**1286.7**	**1266.2**	**1305.6**	**1343.6**	**1373.9**	**1398.3**	**1458.8**	**1605.2**	**1777.3**	**1936.3**

Note: 1989 is last year of actual data.

Table A4-5 (Continued)
End Use Demand by Fuel and Sector - British Columbia and Territories

(Petajoules)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Electricity	44.2	45.2	46.1	46.6	47.1	47.3	47.7	49.5	52.5	56.2
Oil	17.2	16.1	16.3	16.2	16.0	15.8	15.5	14.3	13.7	13.0
Natural Gas	76.6	79.3	82.4	83.3	84.3	85.3	86.5	92.3	94.9	97.1
Propane and Butanes	2.0	1.8	1.9	1.9	1.9	1.9	1.9	2.0	2.1	2.2
Wood	9.7	8.9	9.1	9.2	9.2	9.3	9.3	9.6	9.8	10.1
Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**150.0**	**151.6**	**156.0**	**157.4**	**158.8**	**159.9**	**161.2**	**168.0**	**173.3**	**178.8**
Commercial										
Electricity	40.0	40.8	42.2	42.5	42.9	43.4	44.0	47.0	50.2	53.6
Oil	15.0	14.3	14.7	14.6	14.5	14.4	14.4	14.2	13.9	13.7
Natural Gas	33.1	35.2	36.4	36.6	36.9	37.3	37.7	40.0	42.5	45.2
Propane and Butanes	4.1	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**92.2**	**94.4**	**97.4**	**97.7**	**98.2**	**99.1**	**100.1**	**105.2**	**110.7**	**116.4**
Industrial										
Electricity	99.4	101.5	103.4	107.2	110.4	113.8	116.7	129.7	143.9	151.8
Oil	52.7	53.1	40.1	42.2	43.3	44.5	45.0	55.3	67.3	75.7
Natural Gas	96.3	98.7	113.3	111.5	113.0	115.0	117.1	109.3	109.2	113.1
Coal, Coke and Coke Oven Gas	4.8	4.8	4.8	4.8	4.9	5.0	5.1	5.3	5.4	5.5
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hog Fuel and Pulping Liquor	193.2	194.2	189.9	189.5	189.7	192.4	194.5	196.7	199.5	203.6
Propane and Butanes	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	3.0	3.1
Natural Gas for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal for Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.4	0.5
Total	**449.0**	**454.8**	**454.1**	**457.9**	**464.0**	**473.5**	**481.3**	**499.2**	**528.6**	**553.3**
Non-Energy										
Asphalt	10.5	11.6	12.5	13.1	13.7	14.2	14.6	16.3	18.1	20.0
Lubes and Greases	4.3	4.5	4.5	4.6	4.7	4.3	4.9	5.4	5.9	6.5
Naphtha	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.8	0.9
Petroleum Coke	4.2	4.2	4.3	4.3	4.4	4.5	4.5	4.9	5.3	5.7
Natural Gas	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7	18.7
Oil	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Propane and Butanes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.9
Total	**39.9**	**41.2**	**42.3**	**43.0**	**43.8**	**44.5**	**45.1**	**47.7**	**50.7**	**53.8**
Transportation										
Motor Gasoline	132.6	130.6	129.0	129.0	129.7	130.6	131.4	135.1	138.1	141.3
Diesel Fuel Oil	72.5	71.6	71.8	73.1	74.4	75.6	76.7	80.8	83.7	86.9
Aviation Turbo - Total	36.8	36.5	36.9	38.5	39.5	40.3	41.0	44.8	48.0	52.5
Aviation Gasoline	1.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Heavy Fuel Oil	16.7	17.4	18.0	18.9	19.6	20.2	20.6	21.7	22.0	22.8
Other	6.2	6.2	6.5	6.8	7.0	7.3	7.6	9.0	10.4	11.8
Total	**266.3**	**263.8**	**263.6**	**267.8**	**271.6**	**275.4**	**278.8**	**292.8**	**303.6**	**316.8**
Total End Use										
Electricity	183.9	187.8	192.0	196.7	200.7	204.9	208.7	226.5	247.0	262.1
Oil	366.2	363.6	351.8	358.3	363.4	368.5	372.5	396.6	420.0	442.4
Natural Gas	225.6	232.6	251.8	251.3	254.2	257.9	261.7	263.0	269.1	278.8
Coal, Coke and Coke Oven Gas	4.8	4.8	4.8	4.8	4.9	5.0	5.1	5.3	5.4	5.5
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	9.7	8.9	9.1	9.2	9.2	9.3	9.3	9.6	9.8	10.1
Hog Fuel and Pulping Liquor	193.2	194.2	189.9	189.5	189.7	192.4	194.5	196.7	199.5	203.6
Other	14.1	13.9	14.1	14.2	14.3	14.5	14.6	15.2	15.9	16.6
Total	**997.4**	**1005.7**	**1013.4**	**1023.9**	**1036.4**	**1052.3**	**1066.5**	**1113.0**	**1166.8**	**1219.1**

Note: 1989 is last year of actual data.

Table A4-6
End Use Demand by Fuel - Atlantic Provinces

(Petajoules)

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Newfoundland										
Electricity	35.0	35.7	36.8	37.8	39.1	40.6	41.8	48.7	51.4	52.6
Oil Products	85.3	82.0	80.2	82.2	85.1	89.3	90.3	95.6	99.3	100.8
Other	23.4	22.4	21.8	22.4	23.2	24.7	25.6	26.9	28.5	27.6
Total	**143.7**	**140.1**	**138.8**	**142.4**	**147.4**	**154.6**	**157.7**	**171.2**	**179.2**	**181.0**
Prince Edward Island										
Electricity	2.3	2.4	2.5	2.6	2.6	2.7	2.8	3.1	3.4	3.7
Oil Products	17.3	16.9	17.3	17.6	17.6	16.9	16.8	16.3	16.2	16.7
Other	4.0	4.0	4.3	4.2	4.2	3.8	3.8	3.9	3.9	3.8
Total	**23.6**	**23.3**	**24.1**	**24.4**	**24.4**	**23.4**	**23.4**	**23.3**	**23.5**	**24.2**
Nova Scotia										
Electricity	29.7	31.1	31.6	32.1	32.6	33.2	33.7	36.4	38.4	40.7
Oil Products	133.1	132.8	132.0	131.6	131.7	134.2	134.3	138.0	140.0	143.3
Other	30.2	29.8	29.0	28.3	27.7	28.9	29.8	27.4	27.1	29.0
Total	**193.0**	**193.7**	**192.6**	**192.0**	**192.0**	**196.3**	**197.8**	**201.8**	**205.5**	**213.0**
New Brunswick										
Electricity	44.7	46.5	47.7	48.4	49.4	50.4	51.1	57.0	60.2	62.4
Oil Products	102.9	101.0	105.2	106.4	106.9	103.6	104.1	108.4	111.3	113.6
Other	28.1	27.4	29.0	29.2	28.9	27.3	26.3	24.1	24.3	26.1
Total	**175.7**	**174.9**	**181.9**	**184.0**	**185.2**	**181.3**	**181.5**	**189.5**	**195.8**	**202.1**

Note: 1989 is last year of actual data.

Table A4-7
Total Petroleum Product Demand - Canada and Regions

(Petajoules)

Canada

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	5.4	5.5	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Motor Gasoline	1147.9	1120.5	1102.6	1101.3	1101.3	1103.4	1107.1	1131.2	1155.8	1177.6
Av. Turbo - Kerosene (Jet A-1)	162.0	153.8	155.3	161.7	165.7	168.8	171.6	186.5	198.6	215.8
- Naphtha (Jet B)	24.6	25.4	25.1	25.7	25.8	25.7	25.6	25.0	23.7	22.6
- Total	186.6	179.1	180.5	187.4	191.5	194.5	197.2	211.6	222.3	238.4
Light Fuel and Kerosene	296.2	290.2	294.4	287.5	281.5	276.1	271.2	242.8	226.6	218.8
Diesel Fuel Oil	671.0	667.3	674.0	684.4	695.9	706.1	715.3	752.3	786.3	818.7
Heavy Fuel Oil	448.8	424.7	375.8	377.9	390.5	402.5	386.4	436.1	547.0	746.4
Asphalt	129.2	133.0	135.7	137.7	141.5	145.3	148.8	163.6	181.1	200.6
Lubes and Greases	36.7	38.1	38.4	38.9	39.5	40.2	41.0	45.3	50.1	55.4
Petrochemical Feedstock	120.7	121.7	123.8	126.0	128.2	130.4	132.7	144.8	158.2	173.0
Refinery LPG	63.4	65.1	64.8	65.4	66.2	67.0	67.7	71.1	75.9	82.3
Other Products	286.8	282.9	282.9	287.0	292.7	298.0	302.3	325.4	354.0	389.2
Total Products [a]	**3392.8**	**3328.1**	**3278.3**	**3299.0**	**3334.2**	**3369.0**	**3375.3**	**3529.6**	**3762.4**	**4105.8**

Atlantic

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Motor Gasoline	99.2	97.3	96.2	96.4	96.6	96.9	97.1	98.0	99.0	99.9
Av. Turbo - Kerosene (Jet A-1)	15.4	14.7	14.8	15.5	15.9	16.2	16.4	17.9	19.1	20.8
- Naphtha (Jet B)	4.8	6.3	6.3	6.4	6.4	6.4	6.4	6.3	5.9	5.7
- Total	20.3	21.0	21.1	21.9	22.3	22.6	22.8	24.2	25.0	26.5
Light Fuel and Kerosene	76.7	78.7	79.6	78.9	79.0	79.7	80.7	76.7	76.7	77.8
Diesel Fuel Oil	67.4	66.7	68.7	70.3	72.1	73.5	74.4	79.8	82.7	85.4
Heavy Fuel Oil	196.4	162.3	152.5	148.2	153.0	153.7	130.5	129.5	140.9	164.3
Asphalt	12.8	12.7	13.6	14.1	14.7	15.1	15.4	17.1	18.7	20.1
Lubes and Greases	2.4	2.5	2.5	2.5	2.6	2.6	2.6	2.9	3.1	3.3
Petrochemical Feedstock	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Refinery LPG	5.7	7.9	8.1	8.3	8.4	8.6	8.6	9.0	9.5	10.0
Other Products	24.2	22.1	21.7	21.7	22.1	22.3	21.4	21.5	22.4	23.7
Total Products [a]	**510.7**	**476.7**	**469.5**	**467.6**	**476.2**	**480.3**	**459.1**	**464.1**	**483.5**	**516.6**

Notes: 1989 last year of actual data.

[a] Fuels used to generate electricity exports are not included.

(Petajoules)

Quebec

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Motor Gasoline	252.0	245.8	242.8	242.9	243.2	243.9	245.1	250.4	253.5	256.5
Av. Turbo - Kerosene (Jet A-1)	34.6	31.4	31.7	33.1	33.9	34.6	35.2	38.4	41.0	44.8
- Naphtha (Jet B)	2.7	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.4	2.3
- Total	37.3	34.0	34.3	35.7	36.6	37.2	37.8	41.0	43.5	47.1
Light Fuel and Kerosene	97.5	93.2	94.4	91.2	87.9	84.6	81.2	67.9	58.3	56.8
Diesel Fuel Oil	125.2	123.0	126.5	128.6	130.5	132.4	134.1	139.8	145.4	151.8
Heavy Fuel Oil	104.7	115.7	100.4	103.0	106.8	114.3	118.4	140.1	168.4	208.9
Asphalt	32.8	33.3	34.9	36.1	37.5	38.9	40.1	44.6	49.3	54.8
Lubes and Greases	6.1	6.4	6.2	6.2	6.2	6.2	6.3	6.8	7.5	8.3
Petrochemical Feedstock	15.5	15.7	16.0	16.3	16.7	17.0	17.3	19.1	21.1	23.3
Refinery LPG	8.8	8.8	8.7	8.8	8.9	9.0	9.1	9.6	10.2	11.0
Other Products	63.2	63.6	63.8	64.9	66.0	67.4	68.6	74.6	81.6	90.1
Total Products [a]	**743.9**	**740.3**	**728.8**	**734.5**	**741.2**	**751.6**	**758.8**	**794.6**	**839.6**	**909.5**

Ontario

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	1.3	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6
Motor Gasoline	429.2	423.7	421.3	425.4	427.0	429.1	431.8	448.2	465.7	477.2
Av. Turbo - Kerosene (Jet A-1)	54.7	50.2	50.8	53.0	54.4	55.5	56.5	61.9	66.4	72.7
- Naphtha (Jet B)	3.0	2.7	2.6	2.7	2.7	2.7	2.7	2.6	2.5	2.4
- Total	57.7	52.9	53.5	55.7	57.1	58.2	59.2	64.5	68.9	75.1
Light Fuel and Kerosene	83.4	83.3	85.1	82.5	80.1	77.9	75.9	67.3	60.5	53.9
Diesel Fuel Oil	173.7	174.8	176.0	179.2	182.1	185.0	187.6	199.3	210.5	223.1
Heavy Fuel Oil	95.7	94.6	83.1	83.3	85.6	88.1	90.6	109.0	168.9	293.1
Asphalt	37.9	38.5	36.8	36.0	36.1	36.6	37.3	41.2	46.4	52.7
Lubes and Greases	16.8	17.4	17.6	17.8	18.1	18.5	19.0	21.3	23.9	26.9
Petrochemical Feedstock	89.1	90.0	91.8	93.6	95.5	97.4	99.3	109.7	121.1	133.7
Refinery LPG	22.7	22.5	22.3	22.5	22.7	22.9	23.2	24.6	26.9	30.6
Other Products	92.1	88.3	88.0	89.0	90.2	91.4	92.7	99.2	108.7	123.4
Total Products [a]	**1099.5**	**1087.5**	**1076.9**	**1086.6**	**1096.0**	**1106.8**	**1118.1**	**1185.8**	**1302.9**	**1491.2**

Notes: 1989 last year of actual data.

[a] Fuels used to generate electricity exports are not included.

Table A4-7 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules)	Manitoba									
	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
Motor Gasoline	47.6	45.1	43.0	42.0	41.6	41.3	41.1	40.2	39.3	40.0
Av. Turbo - Kerosene (Jet A-1)	4.9	6.1	6.1	6.2	6.2	6.2	6.2	6.0	5.7	5.4
- Naphtha (Jet B)	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.2
- Total	6.4	7.5	7.4	7.6	7.6	7.6	7.6	7.4	7.0	6.6
Light Fuel and Kerosene	4.1	3.0	3.0	3.0	2.9	2.9	2.8	2.7	2.7	2.8
Diesel Fuel Oil	33.1	35.1	34.6	35.0	35.3	35.5	35.7	37.3	37.8	38.5
Heavy Fuel Oil	2.1	2.7	2.8	2.8	2.8	2.8	2.8	3.1	3.8	4.5
Asphalt	3.3	3.6	3.2	3.0	2.8	2.7	2.7	2.7	2.9	3.2
Lubes and Greases	1.3	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.5
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery LPG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Total Products [a]	**99.1**	**99.2**	**96.3**	**95.5**	**95.2**	**94.9**	**94.8**	**95.5**	**95.8**	**98.1**

	Saskatchewan									
	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3
Motor Gasoline	59.7	55.9	52.5	49.9	48.3	46.9	45.7	42.5	41.0	41.6
Av. Turbo - Kerosene (Jet A-1)	2.0	1.7	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9
- Naphtha (Jet B)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.2	1.1
- Total	3.3	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.1	3.1
Light Fuel and Kerosene	4.8	4.1	4.0	3.9	3.7	3.6	3.5	2.9	2.9	2.9
Diesel Fuel Oil	47.4	46.2	46.4	46.7	47.2	47.6	48.0	50.0	50.9	52.2
Heavy Fuel Oil	3.2	1.8	2.1	2.2	2.4	2.5	2.5	2.7	3.3	3.8
Asphalt	9.2	8.7	9.1	9.2	9.5	9.7	9.9	10.6	11.3	12.4
Lubes and Greases	1.6	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.3	2.5
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refinery LPG	2.3	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.3
Other Products	6.0	5.7	5.6	5.6	5.6	5.6	5.6	5.7	5.9	6.3
Total Products [a]	**137.9**	**129.6**	**127.0**	**124.9**	**124.2**	**123.4**	**122.6**	**122.2**	**123.4**	**127.4**

Notes: 1989 last year of actual data.

[a] Fuels used to generate electricity exports are not included.

(Petajoules)

Alberta

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.4
Motor Gasoline	129.3	123.8	119.4	117.4	116.6	116.5	116.7	118.6	120.8	122.7
Av. Turbo - Kerosene (Jet A-1)	18.5	18.1	18.2	18.8	19.1	19.4	19.6	20.5	21.1	22.1
- Naphtha (Jet B)	6.2	6.1	6.1	6.2	6.2	6.2	6.2	6.0	5.7	5.5
- Total	24.7	24.2	24.3	25.0	25.4	25.6	25.8	26.6	26.8	27.6
Light Fuel and Kerosene	3.2	3.2	3.3	3.4	3.4	3.4	3.4	3.2	3.7	4.0
Diesel Fuel Oil	112.2	111.2	112.2	113.3	115.4	117.1	118.9	122.9	126.9	130.5
Heavy Fuel Oil	1.1	1.3	0.7	1.3	1.5	1.5	1.3	1.2	3.4	4.4
Asphalt	22.8	24.6	25.7	26.3	27.3	28.1	28.8	31.2	34.4	37.3
Lubes and Greases	4.1	4.3	4.5	4.6	4.8	4.9	5.0	5.5	5.9	6.4
Petrochemical Feedstock	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
Refinery LPG	18.9	18.8	18.7	18.8	19.1	19.3	19.5	20.3	21.4	22.2
Other Products	76.5	78.8	80.0	81.5	84.2	86.4	88.7	97.2	106.4	114.9
Total Products [a]	**403.1**	**400.5**	**398.9**	**401.9**	**407.9**	**413.0**	**418.3**	**437.0**	**460.1**	**480.3**

British Columbia and Territories

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Aviation Gasoline	1.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Motor Gasoline	130.9	128.9	127.3	127.4	128.0	128.9	129.8	133.4	136.4	139.6
Av. Turbo - Kerosene (Jet A-1)	31.8	31.5	32.0	33.4	34.4	35.2	35.9	39.9	43.3	48.0
- Naphtha (Jet B)	5.0	5.0	4.9	5.0	5.1	5.1	5.0	4.9	4.7	4.5
- Total	36.8	36.5	36.9	38.5	39.5	40.3	41.0	44.8	48.0	52.5
Light Fuel and Kerosene	26.5	24.7	25.0	24.7	24.4	24.0	23.7	22.1	21.7	20.6
Diesel Fuel Oil	112.0	110.3	109.7	111.4	113.3	115.1	116.7	123.1	131.9	137.1
Heavy Fuel Oil	45.5	46.3	34.2	37.0	38.3	39.6	40.4	50.5	58.2	67.4
Asphalt	10.5	11.6	12.5	13.1	13.7	14.2	14.6	16.3	18.1	20.0
Lubes and Greases	4.3	4.5	4.6	4.6	4.7	4.8	4.9	5.4	6.0	6.5
Petrochemical Feedstock	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Refinery LPG	5.1	5.0	4.9	5.0	5.0	5.1	5.1	5.5	5.8	6.1
Other Products	24.2	24.1	23.6	24.0	24.3	24.7	25.0	26.8	28.6	30.4
Total Products [a]	**398.5**	**394.3**	**380.9**	**388.0**	**393.6**	**399.1**	**403.6**	**430.2**	**457.1**	**482.7**

Notes: 1989 last year of actual data.

[a] Fuels used to generate electricity exports are not included.

Table A5-1

Generating Capacity by Fuel Type - Canada, Provinces and Territories

Gigawatts — **Canada Control Case**

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	17.0	17.3	17.5	17.8	17.9	18.4	18.9	18.8	18.9	20.0
Oil	5.5	5.5	5.5	5.5	5.5	5.4	5.5	5.5	5.5	5.7
Gas	2.6	2.5	2.8	3.0	3.2	3.5	3.7	4.0	4.3	4.5
Other	0.6	0.7	0.7	0.8	0.9	0.9	0.9	1.0	1.0	1.0
Other Fossil Fuelled										
Comb. Turbines	2.4	2.4	2.8	2.9	3.0	3.1	3.2	3.9	4.6	5.4
Int. Combustion	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6
Nuclear	11.2	12.5	13.9	15.3	15.3	15.3	15.3	14.5	13.9	16.6
Hydro/Pumped Storage	57.5	58.0	59.5	60.8	61.4	63.0	64.0	66.7	74.2	79.0
Total Generating Capacity	**97.2**	**99.4**	**103.2**	**106.6**	**107.7**	**110.1**	**111.9**	**114.8**	**122.8**	**132.7**
Purchases[a]	6.5	6.5	6.9	6.9	6.9	6.8	6.7	8.1	10.4	10.4
Capacity Available	103.7	106.0	110.1	113.5	114.6	116.9	118.5	123.0	133.2	143.0
Sales (Export)	6.2	6.4	6.6	6.8	6.9	6.9	7.3	8.8	11.7	11.7
Domestic Peak Demand	83.0	81.6	83.1	84.1	85.2	86.5	87.3	92.9	99.9	107.5
System Peak	89.1	88.0	89.7	90.9	92.1	93.3	94.6	101.7	111.6	119.2
Remaining Capacity	14.6	17.9	20.5	22.6	22.4	23.6	23.9	21.2	21.6	23.8
% of System Peak	16.4	20.4	22.8	24.9	24.3	25.3	25.3	20.9	19.3	20.0

(Megawatts) — **Newfoundland Control Case**

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	525.0	525.0	525.0	525.0	525.0	525.0	675.0	675.0	675.0	675.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Other Fossil Fuelled										
Comb. Turbines	122.0	122.0	122.0	122.0	172.0	272.0	272.0	372.0	372.0	372.0
Int. Combustion	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0	67.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	6295.0	6295.0	6295.0	6295.0	6295.0	6295.0	6295.0	7427.0	8559.0	8559.0
Total Generating Capacity	**7014.0**	**7014.0**	**7014.0**	**7014.0**	**7064.0**	**7164.0**	**7314.0**	**8546.0**	**9678.0**	**9678.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	7014.0	7014.0	7014.0	7014.0	7064.0	7164.0	7314.0	8546.0	9678.0	9678.0
Sales (Export)	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4700.0	4982.0	6114.0	6114.0
Domestic Peak Demand	1981.0	2032.0	2071.0	2093.0	2150.0	2241.0	2295.0	2713.0	2937.0	3148.0
System Peak	6681.0	6732.0	6771.0	6793.0	6850.0	6941.0	6995.0	7695.0	9051.0	9262.0
Remaining Capacity	333.0	282.0	243.0	221.0	214.0	223.0	319.0	851.0	627.0	416.0
% of System Peak	5.0	4.2	3.6	3.3	3.1	3.2	4.6	11.1	6.9	4.5

Notes: The numbers in this table have been rounded.

[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Nova Scotia
Control Case

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	1013.0	1013.0	1163.0	1163.0	1328.0	1328.0	1328.0	1328.0	1328.0	1493.0
Oil	526.0	526.0	529.0	556.0	556.0	556.0	556.0	556.0	556.0	556.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	19.0	19.0	19.0	19.0	19.0	19.0	19.0	69.0	69.0	69.0
Other Fossil Fuelled										
Comb. Turbines	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	255.0
Int. Combustion	2.0	2.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0
Total Generating Capacity	**2151.0**	**2151.0**	**2303.0**	**2330.0**	**2495.0**	**2495.0**	**2495.0**	**2545.0**	**2545.0**	**2760.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	2151.0	2151.0	2303.0	2330.0	2495.0	2495.0	2495.0	2545.0	2545.0	2760.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	1696.0	1750.0	1772.0	1804.0	1813.0	1846.0	1867.0	1933.0	2015.0	2172.0
System Peak	1696.0	1750.0	1772.0	1804.0	1813.0	1846.0	1867.0	1933.0	2015.0	2172.0
Remaining Capacity	455.0	401.0	531.0	526.0	682.0	649.0	628.0	612.0	530.0	588.0
% of System Peak	26.8	22.9	30.0	29.2	37.6	35.2	33.6	31.7	26.3	27.1

(Megawatts)

Prince Edward Island
Control Case

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	66.0	66.0	66.0	63.0	63.0	63.0	63.0	56.0	39.0	20.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	39.0	39.0	39.0	39.0	39.0	39.0	39.0	59.0	89.0	129.0
Int. Combustion	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Generating Capacity	**112.0**	**112.0**	**112.0**	**109.0**	**109.0**	**109.0**	**109.0**	**122.0**	**135.0**	**156.0**
Purchases[a]	70.0	70.0	70.0	70.0	70.0	70.0	50.0	50.0	50.0	50.0
Capacity Available	182.0	182.0	182.0	179.0	179.0	179.0	159.0	172.0	185.0	206.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	134.0	139.0	143.0	146.0	149.0	152.0	137.0	153.0	171.0	191.0
System Peak	134.0	139.0	143.0	146.0	149.0	152.0	137.0	153.0	171.0	191.0
Remaining Capacity	48.0	43.0	39.0	33.0	30.0	27.0	22.0	19.0	14.0	15.0
% of System Peak	35.8	30.9	27.3	22.6	20.1	17.8	16.1	12.4	8.2	7.9

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)

Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

New Brunswick
Control Case

Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	284.0	284.0	284.0	284.0	284.0	797.0	827.0	827.0	827.0	1267.0
Oil	1449.0	1449.0	1449.0	1471.0	1471.0	1368.0	1368.0	1368.0	1368.0	1368.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	63.0	63.0	63.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
Other Fossil Fuelled										
Comb. Turbines	22.0	22.0	422.0	522.0	522.0	522.0	522.0	522.0	522.0	672.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	635.0	635.0	635.0	635.0	635.0	635.0	635.0	635.0	635.0	635.0
Hydro/Pumped Storage	928.0	928.0	928.0	928.0	928.0	928.0	928.0	928.0	928.0	928.0
Total Generating Capacity	**3382.0**	**3382.0**	**3782.0**	**3906.0**	**3906.0**	**4316.0**	**4346.0**	**4346.0**	**4346.0**	**4936.0**
Purchases[a]	350.0	350.0	350.0	350.0	300.0	250.0	0.0	0.0	0.0	0.0
Capacity Available	3732.0	3732.0	4132.0	4256.0	4206.0	4566.0	4346.0	4346.0	4346.0	4936.0
Sales (Export)	387.0	327.0	727.0	727.0	727.0	727.0	677.0	577.0	477.0	477.0
Domestic Peak Demand	2439.0	2543.0	2579.0	2597.0	2638.0	2686.0	2681.0	2928.0	3109.0	3284.0
System Peak	2826.0	2870.0	3306.0	3324.0	3365.0	3413.0	3358.0	3505.0	3586.0	3761.0
Remaining Capacity	906.0	862.0	826.0	932.0	841.0	1153.0	988.0	841.0	760.0	1175.0
% of System Peak	32.1	30.0	25.0	28.0	25.0	33.8	29.4	24.0	21.2	31.2

(Megawatts)

Atlantic
Control Case

Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	1297.0	1297.0	1447.0	1447.0	1612.0	2125.0	2155.0	2155.0	2155.0	2760.0
Oil	2566.0	2566.0	2569.0	2615.0	2615.0	2512.0	2662.0	2655.0	2638.0	2619.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	87.0	87.0	87.0	89.0	89.0	89.0	89.0	139.0	139.0	139.0
Other Fossil Fuelled										
Comb. Turbines	388.0	388.0	788.0	888.0	938.0	1038.0	1038.0	1158.0	1188.0	1428.0
Int. Combustion	77.0	77.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0	76.0
Nuclear	635.0	635.0	635.0	635.0	635.0	635.0	635.0	635.0	635.0	635.0
Hydro/Pumped Storage	7609.0	7609.0	7609.0	7609.0	7609.0	7609.0	7609.0	8741.0	9873.0	9873.0
Total Generating Capacity	**12659.0**	**12659.0**	**13211.0**	**13359.0**	**13574.0**	**14084.0**	**14264.0**	**15559.0**	**16704.0**	**17530.0**
Purchases[a]	420.0	420.0	420.0	420.0	370.0	320.0	50.0	50.0	50.0	50.0
Capacity Available	13079.0	13079.0	13631.0	13779.0	13944.0	14404.0	14314.0	15609.0	16754.0	17580.0
Sales (Export)	5087.0	5027.0	5427.0	5427.0	5427.0	5427.0	5377.0	5559.0	6591.0	6591.0
Domestic Peak Demand	6250.0	6464.0	6565.0	6640.0	6750.0	6925.0	6980.0	7727.0	8232.0	8795.0
System Peak	11337.0	11491.0	11992.0	12067.0	12177.0	12352.0	12357.0	13286.0	14823.0	15386.0
Remaining Capacity	1742.0	1588.0	1639.0	1712.0	1767.0	2052.0	1957.0	2323.0	1931.0	2194.0
% of System Peak	15.4	13.8	13.7	14.2	14.5	16.6	15.8	17.5	13.0	14.3

Notes: The numbers in this table have been rounded.

[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)					Quebec Control Case					
Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	615.0	615.0	615.0	465.0	470.0	470.0	470.0	470.0	470.0	470.0
Gas	7.0	7.0	27.0	207.0	240.0	280.0	330.0	330.0	330.0	330.0
Other	10.0	10.0	10.0	10.0	30.0	30.0	30.0	30.0	30.0	30.0
Other Fossil Fuelled										
Comb. Turbines	441.0	441.0	441.0	441.0	441.0	441.0	441.0	741.0	741.0	741.0
Int. Combustion	62.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0
Nuclear	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0	685.0
Hydro/Pumped Storage	26434.0	26544.0	27543.0	28494.0	29104.0	30578.0	31232.0	32072.0	35776.0	39352.0
Total Generating Capacity	**28254.0**	**28421.0**	**29440.0**	**30421.0**	**31089.0**	**32603.0**	**33307.0**	**34447.0**	**38151.0**	**41727.0**
Purchases[a]	5100.0	5100.0	5500.0	5500.0	5500.0	5500.0	5500.0	5782.0	6914.0	6914.0
Capacity Available	33354.0	33521.0	34940.0	35921.0	36589.0	38103.0	38807.0	40229.0	45065.0	48641.0
Sales (Export)	795.0	852.0	768.0	721.0	671.0	621.0	1098.0	1506.0	2756.0	2756.0
Domestic Peak Demand	29606.0	29149.0	29629.0	29994.0	30457.0	30962.0	31487.0	33977.0	36881.0	39681.0
System Peak	30401.0	30001.0	30397.0	30715.0	31128.0	31583.0	32585.0	35483.0	39637.0	42437.0
Remaining Capacity	2953.0	3520.0	4543.0	5206.0	5461.0	6520.0	6222.0	4746.0	5428.0	6204.0
% of System Peak	9.7	11.7	14.9	16.9	17.5	20.6	19.1	13.4	13.7	14.6

(Megawatts)					Ontario Control Case					
Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	8810.0	8810.0	8810.0	8810.0	8810.0	8810.0	8810.0	8910.0	8910.0	8910.0
Oil	2232.0	2232.0	2257.0	2282.0	2282.0	2302.0	2302.0	2302.0	2302.0	2476.0
Gas	292.0	325.0	496.0	582.0	668.0	741.0	820.0	1208.0	1452.0	1669.0
Other	63.0	75.0	120.0	138.0	146.0	154.0	164.0	164.0	164.0	164.0
Other Fossil Fuelled										
Comb. Turbines	833.0	833.0	833.0	833.0	833.0	852.0	852.0	852.0	1188.0	1628.0
Int. Combustion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	9909.0	11156.0	12552.0	13948.0	13948.0	13948.0	13948.0	13208.0	12597.0	15240.0
Hydro/Pumped Storage	7188.0	7207.0	7207.0	7207.0	7207.0	7207.0	7207.0	7207.0	8281.0	9039.0
Total Generating Capacity	**29327.0**	**30638.0**	**32275.0**	**33800.0**	**33894.0**	**34014.0**	**34103.0**	**33851.0**	**34894.0**	**39126.0**
Purchases[a]	56.0	56.0	56.0	56.0	56.0	56.0	56.0	456.0	1056.0	1056.0
Capacity Available	29383.0	30694.0	32331.0	33856.0	33950.0	34070.0	34159.0	34307.0	35950.0	40182.0
Sales (Export)	47.0	92.0	47.0	47.0	2.0	2.0	2.0	2.0	2.0	2.0
Domestic Peak Demand	25315.0	24513.0	25032.0	25251.0	25542.0	25968.0	26378.0	27368.0	29349.0	32012.0
System Peak	25362.0	24605.0	25079.0	25298.0	25544.0	25970.0	26380.0	27370.0	29351.0	32014.0
Remaining Capacity	4021.0	6089.0	7252.0	8558.0	8406.0	8100.0	7779.0	6937.0	6599.0	8168.0
% of System Peak	15.9	24.7	28.9	33.8	32.9	31.2	29.5	25.3	22.5	25.5

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Manitoba
Control Case

Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	369.0	369.0	369.0	369.0	369.0	369.0	369.0	237.0	105.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	39.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Other	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
Other Fossil Fuelled										
Comb. Turbines	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Int. Combustion	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	3498.0	3882.0	4394.0	4778.0	4778.0	4778.0	4778.0	5516.0	6008.0	6184.0
Total Generating Capacity	**3983.0**	**4332.0**	**4844.0**	**5228.0**	**5228.0**	**5228.0**	**5228.0**	**5834.0**	**6194.0**	**6265.0**
Purchases[a]	300.0	300.0	300.0	300.0	300.0	300.0	300.0	500.0	500.0	500.0
Capacity Available	4283.0	4632.0	5144.0	5528.0	5528.0	5528.0	5528.0	6334.0	6694.0	6765.0
Sales (Export)	112.0	200.0	200.0	500.0	700.0	700.0	700.0	900.0	1500.0	1500.0
Domestic Peak Demand	3429.0	3235.0	3287.0	3374.0	3474.0	3520.0	3560.0	3720.0	3832.0	4075.0
System Peak	3541.0	3435.0	3487.0	3874.0	4174.0	4220.0	4260.0	4620.0	5332.0	5575.0
Remaining Capacity	742.0	1197.0	1657.0	1654.0	1354.0	1308.0	1268.0	1714.0	1362.0	1190.0
% of System Peak	21.0	34.8	47.5	42.7	32.4	31.0	29.8	37.1	25.5	21.3

(Megawatts)

Saskatchewan
Control Case

Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	1559.0	1559.0	1559.0	1839.0	1839.0	1839.0	1839.0	1839.0	1839.0	2119.0
Oil	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Gas	131.0	131.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0
Other	22.0	22.0	36.0	36.0	41.0	41.0	41.0	41.0	41.0	41.0
Other Fossil Fuelled										
Comb. Turbines	136.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	827.0	827.0	827.0	827.0	827.0	827.0	867.0	867.0	867.0	867.0
Total Generating Capacity	**2697.0**	**2697.0**	**2718.0**	**2998.0**	**3003.0**	**3003.0**	**3043.0**	**3043.0**	**3043.0**	**3323.0**
Purchases[a]	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0	225.0
Capacity Available	2922.0	2922.0	2943.0	3223.0	3228.0	3228.0	3268.0	3268.0	3268.0	3548.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	2503.0	2467.0	2465.0	2447.0	2509.0	2521.0	2519.0	2560.0	2621.0	2735.0
System Peak	2503.0	2467.0	2465.0	2447.0	2509.0	2521.0	2519.0	2560.0	2621.0	2735.0
Remaining Capacity	419.0	455.0	478.0	776.0	719.0	707.0	749.0	708.0	647.0	813.0
% of System Peak	16.7	18.4	19.4	31.7	28.7	28.0	29.7	27.7	24.7	29.7

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) **Alberta Control Case**

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	4919.0	5302.0	5302.0	5302.0	5302.0	5302.0	5708.0	5652.0	5854.0	6229.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	1116.0	1089.0	1120.0	1111.0	1165.0	1179.0	1190.0	1048.0	1081.0	1114.0
Other	65.0	95.0	95.0	121.0	129.0	129.0	129.0	146.0	151.0	159.0
Other Fossil Fuelled										
Comb. Turbines	413.0	421.0	418.0	428.0	429.0	446.0	467.0	755.0	1087.0	1221.0
Int. Combustion	43.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	796.0	796.0	796.0	796.0	796.0	796.0	796.0	796.0	796.0	796.0
Total Generating Capacity	**7352.0**	**7744.0**	**7772.0**	**7799.0**	**7862.0**	**7893.0**	**8331.0**	**8438.0**	**9010.0**	**9560.0**
Purchases[a]	425.0	425.0	425.0	425.0	425.0	425.0	525.0	525.0	525.0	525.0
Capacity Available	7777.0	8169.0	8197.0	8224.0	8287.0	8318.0	8856.0	8963.0	9535.0	10085.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	6109.0	6172.0	6381.0	6427.0	6562.0	6676.0	6719.0	7215.0	7730.0	8157.0
System Peak	6109.0	6172.0	6381.0	6427.0	6562.0	6676.0	6719.0	7215.0	7730.0	8157.0
Remaining Capacity	1668.0	1997.0	1816.0	1797.0	1725.0	1642.0	2137.0	1748.0	1805.0	1928.0
% of System Peak	27.3	32.4	28.5	28.0	26.3	24.6	31.8	24.2	23.4	23.6

(Megawatts) **Prairies Control Case**

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	6847.0	7230.0	7230.0	7510.0	7510.0	7510.0	7916.0	7728.0	7798.0	8348.0
Oil	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Gas	1286.0	1224.0	1262.0	1253.0	1307.0	1321.0	1332.0	1190.0	1223.0	1256.0
Other	110.0	140.0	154.0	180.0	193.0	193.0	193.0	210.0	215.0	223.0
Other Fossil Fuelled										
Comb. Turbines	574.0	582.0	579.0	589.0	590.0	607.0	628.0	916.0	1248.0	1382.0
Int. Combustion	73.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Nuclear										
Hydro/Pumped Storage	5121.0	5505.0	6017.0	6401.0	6401.0	6401.0	6441.0	7179.0	7671.0	7847.0
Total Generating Capacity	**14032.0**	**14773.0**	**15334.0**	**16025.0**	**16093.0**	**16124.0**	**16602.0**	**17315.0**	**18247.0**	**19148.0**
Purchases[a]	950.0	950.0	950.0	950.0	950.0	950.0	1050.0	1250.0	1250.0	1250.0
Capacity Available	14982.0	15723.0	16284.0	16975.0	17043.0	17074.0	17652.0	18565.0	19497.0	20398.0
Sales (Export)	112.0	200.0	200.0	500.0	700.0	700.0	700.0	900.0	1500.0	1500.0
Domestic Peak Demand	12041.0	11874.0	12133.0	12248.0	12545.0	12717.0	12798.0	13495.0	14183.0	14967.0
System Peak	12153.0	12074.0	12333.0	12748.0	13245.0	13417.0	13498.0	14395.0	15683.0	16467.0
Remaining Capacity	2829.0	3649.0	3951.0	4227.0	3798.0	3657.0	4154.0	4170.0	3814.0	3931.0
% of System Peak	23.3	30.2	32.0	33.2	28.7	27.3	30.8	29.0	24.3	23.9

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

(Megawatts)

British Columbia
Control Case

Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Gas	965.0	965.0	965.0	965.0	1013.0	1168.0	1218.0	1268.0	1268.0	1268.0
Other	365.0	365.0	365.0	365.0	422.0	422.0	422.0	422.0	422.0	422.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	10995.0	11001.0	11001.0	11001.0	11001.0	11051.0	11351.0	11351.0	12491.0	12766.0
Total Generating Capacity	**12646.0**	**12652.0**	**12652.0**	**12652.0**	**12757.0**	**12962.0**	**13312.0**	**13362.0**	**14502.0**	**14777.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	600.0	1100.0	1100.0
Capacity Available	12646.0	12652.0	12652.0	12652.0	12757.0	12962.0	13312.0	13962.0	15602.0	15877.0
Sales (Export)	110.0	260.0	110.0	110.0	110.0	110.0	110.0	850.0	850.0	850.0
Domestic Peak Demand	9386.0	9205.0	9343.0	9533.0	9523.0	9474.0	9242.0	9893.0	10786.0	11534.0
System Peak	9496.0	9465.0	9453.0	9643.0	9633.0	9584.0	9352.0	10743.0	11636.0	12384.0
Remaining Capacity	3150.0	3187.0	3199.0	3009.0	3124.0	3378.0	3960.0	3219.0	3966.0	3493.0
% of System Peak	33.2	33.7	33.8	31.2	32.4	35.2	42.3	30.0	34.1	28.2

(Megawatts)

Yukon
Control Case

Type of Capacity	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Int. Combustion	42.0	42.0	42.0	42.0	42.0	42.0	42.0	49.0	56.0	70.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Total Generating Capacity	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**122.0**	**129.0**	**136.0**	**150.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	122.0	122.0	122.0	122.0	122.0	122.0	122.0	129.0	136.0	150.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	79.0	79.0	84.0	87.0	87.0	88.0	89.0	97.0	103.0	111.0
System Peak	79.0	79.0	84.0	87.0	87.0	88.0	89.0	97.0	103.0	111.0
Remaining Capacity	43.0	43.0	38.0	35.0	35.0	34.0	33.0	32.0	33.0	39.0
% of System Peak	54.4	54.4	45.2	40.2	40.2	38.6	37.1	33.0	32.0	35.1

Notes: The numbers in this table have been rounded.
[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-1 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) — **Northwest Territories Control Case**

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fossil Fuelled										
Comb. Turbines	20.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Int. Combustion	118.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	124.0	138.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	43.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
Total Generating Capacity	**181.0**	**177.0**	**177.0**	**177.0**	**177.0**	**177.0**	**177.0**	**177.0**	**184.0**	**198.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	181.0	177.0	177.0	177.0	177.0	177.0	177.0	177.0	184.0	198.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	105.0	118.0	120.0	122.0	124.0	125.0	127.0	136.0	146.0	157.0
System Peak	105.0	118.0	120.0	122.0	124.0	125.0	127.0	136.0	146.0	157.0
Remaining Capacity	76.0	59.0	57.0	55.0	53.0	52.0	50.0	41.0	38.0	41.0
% of System Peak	72.4	50.0	47.5	45.1	42.7	41.6	39.4	30.1	26.0	26.1

(Megawatts) — **British Columbia, Yukon and Northwest Territories Control Case**

Type of Capacity	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Gas	965.0	965.0	965.0	965.0	1013.0	1168.0	1218.0	1268.0	1268.0	1268.0
Other	365.0	365.0	365.0	365.0	422.0	422.0	422.0	422.0	422.0	422.0
Other Fossil Fuelled										
Comb. Turbines	192.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0
Int. Combustion	241.0	240.0	240.0	240.0	240.0	240.0	240.0	247.0	261.0	289.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	11118.0	11122.0	11122.0	11122.0	11122.0	11172.0	11472.0	11472.0	12612.0	12887.0
Total Generating Capacity	**12949.0**	**12951.0**	**12951.0**	**12951.0**	**13056.0**	**13261.0**	**13611.0**	**13668.0**	**14822.0**	**15125.0**
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	600.0	1100.0	1100.0
Capacity Available	12949.0	12951.0	12951.0	12951.0	13056.0	13261.0	13611.0	14268.0	15922.0	16225.0
Sales (Export)	110.0	260.0	110.0	110.0	110.0	110.0	110.0	850.0	850.0	850.0
Domestic Peak Demand	9570.0	9402.0	9547.0	9742.0	9734.0	9687.0	9458.0	10126.0	11035.0	11802.0
System Peak	9680.0	9662.0	9657.0	9852.0	9844.0	9797.0	9568.0	10976.0	11885.0	12652.0
Remaining Capacity	3269.0	3289.0	3294.0	3099.0	3212.0	3464.0	4043.0	3292.0	4037.0	3573.0
% of System Peak	33.8	34.0	34.1	31.5	32.6	35.4	42.3	30.0	34.0	28.2

Notes: The numbers in this table have been rounded.

[a] Excludes imports and interprovincial capacity purchases and reserve sharing.

Table A5-2

Energy Generation by Fuel Type - Canada, Provinces and Territories

rawatt hours				Canada Control Case						
e of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
al Fired Steam										
uminous	38.5	32.5	24.6	23.1	23.6	26.4	33.0	47.3	59.9	63.7
b-Bituminous	35.9	34.5	39.4	40.5	40.9	41.2	41.2	43.8	45.5	48.3
nite	11.2	9.6	9.7	9.7	10.2	10.8	10.3	11.2	10.6	11.4
Fired Steam										
ht	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
avy	15.9	14.5	10.6	10.3	10.7	10.7	8.6	8.1	9.1	11.0
ural Gas Fired Steam	11.9	7.3	5.4	5.6	6.3	8.1	11.1	12.4	14.2	15.1
mb. Turbines										
ht Oil	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.3	1.2
tural Gas	3.0	3.0	2.6	2.7	2.7	2.8	3.0	3.8	4.7	5.2
rnal Combustion										
esel Oil	0.8	0.8	1.1	1.1	1.1	1.1	1.1	1.2	1.3	1.4
clear	75.4	68.8	90.1	100.1	110.2	110.2	110.2	104.8	101.2	113.3
droelectric	287.7	293.5	299.6	315.6	325.1	336.4	342.5	361.0	391.3	412.5
er	3.2	2.4	2.9	3.1	3.6	3.8	4.0	4.3	4.4	4.4
al Energy Generation	**483.8**	**467.1**	**486.2**	**511.9**	**534.4**	**551.6**	**565.4**	**598.1**	**642.4**	**687.5**
. Domestic Consumption	**474.4**	**467.7**	**479.8**	**487.5**	**496.7**	**506.9**	**517.2**	**556.0**	**598.8**	**645.6**
orts (Net)	**9.6**	**-0.6**	**6.4**	**24.4**	**37.8**	**44.8**	**48.2**	**41.5**	**43.6**	**41.9**

gawatt hours				Newfoundland Control Case						
e of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
al Fired Steam										
uminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
b-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
nite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fired Steam										
ht	44.0	48.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
avy	2116.0	2178.0	1686.0	1808.0	2105.0	2457.0	2671.0	318.0	675.0	1127.0
ural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
nb. Turbines										
ht Oil	5.0	35.0	60.0	66.0	83.0	150.0	244.0	0.0	0.0	16.0
tural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
rnal Combustion										
esel Oil	49.0	3.0	73.0	74.0	79.0	80.0	73.0	55.0	55.0	55.0
clear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
droelectric	32830.0	34782.0	40338.0	40338.0	40335.0	40329.0	40330.0	46010.0	51660.0	51660.0
er	0.0	0.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
al Energy Generation	**35044.0**	**37046.0**	**42190.0**	**42319.0**	**42635.0**	**43049.0**	**43351.0**	**46416.0**	**52423.0**	**52891.0**
. Domestic Consumption	**10676.0**	**10882.0**	**11105.0**	**11234.0**	**11550.0**	**11964.0**	**12266.0**	**14175.0**	**15107.0**	**15806.0**
erprovincial Transfers t)	**24368.0**	**26164.0**	**31085.0**	**31085.0**	**31085.0**	**31085.0**	**31085.0**	**32241.0**	**37316.0**	**37085.0**
orts (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

e: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours — **Nova Scotia Control Case**

Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2
Coal Fired Steam										
-Bituminous	5345.0	5207.0	6824.0	7430.0	7362.0	7893.0	7966.0	8575.0	8881.0	982
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil Fired Steam										
-Light	8.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
-Heavy	2518.0	2691.0	1405.0	882.0	935.0	600.0	640.0	803.0	1080.0	100
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Comb. Turbines										
-Light Oil	0.0	0.0	70.0	16.0	21.0	0.0	2.0	15.0	48.0	
-Natural Gas	68.0	19.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Internal Combustion										
-Diesel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Hydroelectric	970.0	1150.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0	1102.0	110
Other	41.0	104.0	143.0	146.0	279.0	280.0	280.0	280.0	280.0	28
Total Energy Generation	8950.0	9180.0	9544.0	9576.0	9699.0	9875.0	9990.0	10775.0	11391.0	122
Tot. Domestic Consumption	9050.0	9429.0	9544.0	9576.0	9699.0	9875.0	9990.0	10775.0	11391.0	122
Interprovincial Transfers (net)	-100.0	-249.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Exports (Net)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Gigawatt hours — **Prince Edward Island Control Case**

Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
-Heavy	98.0	82.0	103.0	108.0	102.0	107.0	209.0	215.0	201.0	1
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Comb. Turbines										
-Light Oil	5.0	4.0	2.0	3.0	4.0	5.0	12.0	22.0	43.0	1
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Internal Combustion										
-Diesel Oil	3.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Hydroelectric	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total Energy Generation	106.0	86.0	105.0	111.0	106.0	112.0	221.0	238.0	244.0	2
Tot. Domestic Consumption	728.0	758.0	773.0	789.0	804.0	820.0	837.0	924.0	1020.0	11
Interprovincial Transfers (net)	-622.0	-672.0	-668.0	-678.0	-698.0	-708.0	-616.0	-686.0	-776.0	-8
Exports (Net)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Note: The numbers in this table have been rounded.

igawatt hours

New Brunswick
Control Case

ype of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
oal Fired Steam										
ituminous	1864.0	1433.0	2016.0	2016.0	2016.0	2016.0	5893.0	5893.0	5893.0	5893.0
ub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
l Fired Steam										
ight	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
leavy	7729.0	6111.0	6494.0	6544.0	6583.0	6581.0	4154.0	5825.0	5822.0	7059.0
atural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
omb. Turbines										
ight Oil	0.0	0.0	1.0	1.0	13.0	28.0	17.0	100.0	191.0	350.0
latural Gas	9.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ternal Combustion										
iesel Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
uclear	5269.0	5338.0	4727.0	4727.0	4727.0	4727.0	4728.0	4728.0	4728.0	4728.0
ydroelectric	2409.0	3483.0	2791.0	2791.0	2791.0	2791.0	2791.0	2791.0	2791.0	2791.0
ther	275.0	289.0	277.0	280.0	286.0	289.0	289.0	289.0	289.0	289.0
otal Energy Generation	**17564.0**	**16656.0**	**16306.0**	**16359.0**	**16416.0**	**16432.0**	**17872.0**	**19626.0**	**19714.0**	**21110.0**
ot. Domestic Consumption	**13566.0**	**14079.0**	**14294.0**	**14327.0**	**14564.0**	**14840.0**	**15025.0**	**16670.0**	**17716.0**	**18732.0**
terprovincial Transfers et)	**-293.0**	**-622.0**	**-1331.0**	**-1621.0**	**-1801.0**	**-2361.0**	**-1883.0**	**687.0**	**467.0**	**872.0**
xports (Net)	**4291.0**	**3199.0**	**3343.0**	**3653.0**	**3653.0**	**3953.0**	**4730.0**	**2269.0**	**1531.0**	**1506.0**

igawatt hours

Atlantic
Control Case

ype of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
oal Fired Steam										
ituminous	7209.0	6640.0	8840.0	9446.0	9378.0	9909.0	13859.0	14468.0	14774.0	15714.0
ub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
il Fired Steam										
ight	61.0	57.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
leavy	12461.0	11062.0	9688.0	9342.0	9725.0	9745.0	7674.0	7161.0	7778.0	9326.0
atural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
omb. Turbines										
ight Oil	10.0	39.0	133.0	86.0	121.0	183.0	275.0	137.0	282.0	530.0
latural Gas										
ternal Combustion										
iesel Oil	52.0	3.0	73.0	74.0	79.0	80.0	73.0	56.0	55.0	55.0
uclear	5269.0	5338.0	4727.0	4727.0	4727.0	4727.0	4728.0	4728.0	4728.0	4728.0
ydroelectric	36209.0	39415.0	44231.0	44231.0	44228.0	44222.0	44223.0	49903.0	55553.0	55553.0
ther	316.0	393.0	453.0	459.0	598.0	602.0	602.0	602.0	602.0	602.0
otal Energy Generation	**61587.0**	**62947.0**	**68145.0**	**68365.0**	**68856.0**	**69468.0**	**71434.0**	**77055.0**	**83772.0**	**86508.0**
ot. Domestic Consumption	**34020.0**	**35148.0**	**35716.0**	**35926.0**	**36617.0**	**37499.0**	**38118.0**	**42544.0**	**45234.0**	**47921.0**
xports (Net)	**4291.0**	**3199.0**	**3343.0**	**3653.0**	**3653.0**	**3953.0**	**4730.0**	**2269.0**	**1531.0**	**1506.0**

ote: The numbers in this table have been rounded.

Table A5-2 (Continued)

Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours — **Quebec Control Case**

Type of Generation	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**20**
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Oil Fired Steam										
-Light	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Heavy	1365.0	1654.0	60.0	60.0	65.0	60.0	50.0	50.0	50.0	53
Natural Gas Fired Steam	19.0	0.0	0.0	0.0	29.0	22.0	0.0	0.0	0.0	20
Comb. Turbines										
-Light Oil	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Internal Combustion										
-Diesel Oil	221.0	256.0	490.0	490.0	490.0	490.0	490.0	490.0	490.0	49
Nuclear	4820.0	4145.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0	5101.0	510
Hydroelectric[a]	139086.0	133055.0	134237.0	144859.0	151329.0	161848.0	167900.0	179387.0	195588.0	20925
Other	0.0	40.0	40.0	40.0	50.0	50.0	50.0	50.0	50.0	5
Total Energy Generation	**145561.0**	**139150.0**	**139928.0**	**150550.0**	**157064.0**	**167571.0**	**173591.0**	**185078.0**	**201279.0**	**21620**
Tot. Domestic Consumption	**163524.0**	**160999.0**	**165145.0**	**167821.0**	**171105.0**	**174809.0**	**178701.0**	**193571.0**	**209467.0**	**22639**
Interprovincial Transfers (net)	**-22400.0**	**-24026.0**	**-28600.0**	**-28297.0**	**-27997.0**	**-26297.0**	**-26264.0**	**-31420.0**	**-36085.0**	**-3616**
Exports (Net)	**4437.0**	**2177.0**	**3383.0**	**11026.0**	**13956.0**	**19059.0**	**21154.0**	**22927.0**	**27897.0**	**2597**

Gigawatt hours — **Ontario Control Case**

Type of Generation	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**20**
Coal Fired Steam										
-Bituminous	30669.0	25234.0	15726.0	13646.0	14217.0	16479.0	19167.0	32808.0	45080.0	4801
-Sub-Bituminous	2400.0	1866.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0	240
-Lignite	1000.0	768.0	1044.0	1000.0	1000.0	1000.0	1000.0	1102.0	1270.0	132
Oil Fired Steam										
-Light	81.0	48.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Heavy	1449.0	1300.0	337.0	337.0	337.0	337.0	337.0	390.0	696.0	61
Natural Gas Fired Steam	867.0	916.0	1250.0	1315.0	1380.0	1445.0	1562.0	1562.0	1562.0	156
Comb. Turbines										
-Light Oil	35.0	19.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Natural Gas	593.0	885.0	867.0	964.0	964.0	964.0	964.0	964.0	1123.0	129
Internal Combustion										
-Diesel Oil	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Nuclear	65261.0	59352.0	80300.0	90315.0	100329.0	100329.0	100329.0	94949.0	91333.0	10345
Hydroelectric	38660.0	40225.0	38851.0	39021.0	39021.0	39121.0	39121.0	39121.0	40388.0	4283
Other	681.0	180.0	345.0	410.0	445.0	480.0	574.0	574.0	574.0	57
Total Energy Generation	141698.0	130794.0	141120.0	149408.0	160093.0	162555.0	165454.0	173870.0	184426.0	20206
Tot. Domestic Consumption	147492.0	144269.0	148774.0	151512.0	154501.0	158096.0	161595.0	171521.0	185185.0	20282
Interprovincial Transfers (net)	**-2244.0**	**-2186.0**	**-1770.0**	**-1770.0**	**-1870.0**	**-3003.0**	**-3603.0**	**-4513.0**	**-7921.0**	**-796**
Exports (Net)	**-3550.0**	**-11289.0**	**-5884.0**	**-334.0**	**7462.0**	**7462.0**	**7462.0**	**6862.0**	**7162.0**	**720**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

igawatt hours — **Manitoba** **Control Case**

ype of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
oal Fired Steam										
ituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ignite	435.0	323.0	0.0	0.0	0.0	0.0	1.0	16.0	0.0	0.0
l Fired Steam										
ight	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
leavy	27.0	13.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
atural Gas Fired Steam	5.0	8.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
omb. Turbines										
ight Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
latural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ternal Combustion										
iesel Oil	26.0	27.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
uclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ydroelectric	18300.0	18926.0	20166.0	24558.0	27572.0	28213.0	28213.0	29463.0	33631.0	34930.0
ther	30.0	30.0	35.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
otal Energy Generation	**18824.0**	**19328.0**	**20241.0**	**24643.0**	**27657.0**	**28298.0**	**28299.0**	**29564.0**	**33716.0**	**35015.0**
ot. Domestic Consumption	**17638.0**	**16629.0**	**17192.0**	**17661.0**	**18189.0**	**18430.0**	**18641.0**	**19481.0**	**20400.0**	**21699.0**
terprovincial Transfers et)	**1348.0**	**1601.0**	**1879.0**	**1879.0**	**1879.0**	**1279.0**	**1819.0**	**4289.0**	**7997.0**	**7997.0**
xports (Net)	**-162.0**	**1098.0**	**1170.0**	**5103.0**	**7589.0**	**8589.0**	**7839.0**	**5794.0**	**5319.0**	**5319.0**

igawatt hours — **Saskatchewan** **Control Case**

ype of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
oal Fired Steam										
ituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ub-Bituminous	54.0	50.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
ignite	9804.0	8493.0	8666.0	8744.0	9177.0	9843.0	9292.0	10052.0	9373.0	10080.0
l Fired Steam										
ight	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
leavy	7.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
atural Gas Fired Steam	538.0	527.0	302.0	307.0	258.0	260.0	260.0	267.0	279.0	251.0
omb. Turbines										
ight Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
latural Gas	84.0	48.0	73.0	77.0	25.0	28.0	28.0	34.0	45.0	16.0
ternal Combustion										
iesel Oil	3.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
uclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ydroelectric	2832.0	4220.0	3710.0	3710.0	3710.0	3710.0	3795.0	3795.0	3795.0	3795.0
ther	169.0	175.0	176.0	178.0	170.0	170.0	170.0	170.0	170.0	170.0
otal Energy Generation	**13491.0**	**13524.0**	**13002.0**	**13091.0**	**13415.0**	**14086.0**	**13620.0**	**14393.0**	**13737.0**	**14387.0**
ot. Domestic Consumption	**13625.0**	**13572.0**	**13654.0**	**13763.0**	**14087.0**	**14158.0**	**14232.0**	**14465.0**	**14809.0**	**15459.0**
terprovincial Transfers et)	**-83.0**	**-66.0**	**-650.0**	**-670.0**	**-670.0**	**-70.0**	**-610.0**	**-70.0**	**-1070.0**	**-1070.0**
xports (Net)	**-51.0**	**18.0**	**-2.0**	**-2.0**	**-2.0**	**-2.0**	**-2.0**	**-2.0**	**-2.0**	**-2.0**

ote: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours — **Alberta** — **Control Case**

Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	20
Coal Fired Steam										
-Bituminous	621.0	585.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Sub-Bituminous	33466.0	32604.0	36931.0	38029.0	38445.0	38748.0	38773.0	41381.0	43074.0	45837
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Heavy	0.0	18.0	20.0	20.0	20.0	20.0	20.0	20.0	30.0	30
Natural Gas Fired Steam	5000.0	4033.0	2675.0	2760.0	3164.0	3500.0	3849.0	4383.0	4939.0	5039
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Natural Gas	2119.0	2058.0	1615.0	1682.0	1715.0	1854.0	2022.0	2750.0	3462.0	3773
Internal Combustion										
-Diesel Oil	15.0	16.0	109.0	109.0	110.0	111.0	111.0	111.0	112.0	110
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Hydroelectric	1598.0	2059.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636
Other	615.0	596.0	800.0	900.0	959.0	959.0	959.0	1084.0	1127.0	1184
Total Energy Generation	**43434.0**	**41969.0**	**43786.0**	**45136.0**	**46049.0**	**46828.0**	**47370.0**	**51365.0**	**54380.0**	**57609**
Tot. Domestic Consumption	**41176.0**	**41136.0**	**42541.0**	**42871.0**	**43784.0**	**44563.0**	**45405.0**	**49200.0**	**52715.0**	**55644**
Interprovincial Transfers (net)	**2261.0**	**836.0**	**1248.0**	**2268.0**	**2268.0**	**2268.0**	**1968.0**	**2168.0**	**1668.0**	**1968**
Exports (Net)	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3**

Gigawatt hours — **Prairies** — **Control Case**

Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	20
Coal Fired Steam										
-Bituminous	621.0	585.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Sub-Bituminous	33520.0	32654.0	36996.0	38094.0	38510.0	38813.0	38838.0	41446.0	43139.0	45902
-Lignite	10239.0	8816.0	8666.0	8744.0	9177.0	9843.0	9293.0	10068.0	9373.0	10080
Oil Fired Steam										
-Light	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Heavy	34.0	41.0	45.0	45.0	45.0	45.0	45.0	45.0	55.0	55
Natural Gas Fired Steam	5543.0	4568.0	2997.0	3087.0	3442.0	3780.0	4129.0	4670.0	5238.0	5310
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Natural Gas	2203.0	2106.0	1688.0	1759.0	1740.0	1882.0	2050.0	2784.0	3507.0	3789
Internal Combustion										
-Diesel Oil	44.0	44.0	114.0	114.0	115.0	116.0	116.0	116.0	117.0	115
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Hydroelectric	22730.0	25205.0	25512.0	29904.0	32918.0	33559.0	33644.0	34894.0	39062.0	40361
Other	814.0	801.0	1011.0	1123.0	1174.0	1174.0	1174.0	1299.0	1342.0	1399
Total Energy Generation	**75749.0**	**74821.0**	**77029.0**	**82870.0**	**87121.0**	**89212.0**	**89289.0**	**95322.0**	**101833.0**	**107011**
Tot. Domestic Consumption	**72439.0**	**71337.0**	**73387.0**	**74295.0**	**76060.0**	**77151.0**	**78278.0**	**83146.0**	**87924.0**	**92802**
Exports (Net)	**-216.0**	**1113.0**	**1165.0**	**5098.0**	**7584.0**	**8584.0**	**7834.0**	**5789.0**	**5314.0**	**5314**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)

Energy Generation by Fuel Type - Canada, Provinces and Territories

British Columbia
Control Case

Gigawatt hours Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Coal Fired Steam										
Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Heavy	632.0	434.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
Natural Gas Fired Steam	5421.0	1776.0	1171.0	1151.0	1484.0	2813.0	5441.0	6213.0	7400.0	8009.0
Comb. Turbines										
Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	45.0	70.0
Natural Gas	1.0	1.0	0.0	0.0	0.0	0.0	0.0	6.0	43.0	65.0
Internal Combustion										
Diesel Oil	242.0	219.0	70.0	70.0	70.0	70.0	70.0	70.0	87.0	98.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric[a]	50393.0	54949.0	56113.0	56851.0	56925.0	56941.0	56923.0	56991.0	59995.0	63798.0
Other	1416.0	960.0	1095.0	1115.0	1300.0	1473.0	1620.0	1808.0	1808.0	1808.0
Total Energy Generation	**58105.0**	**58339.0**	**58949.0**	**59687.0**	**60279.0**	**61797.0**	**64554.0**	**65590.0**	**69878.0**	**74348.0**
Tot. Domestic Consumption	**55912.0**	**54909.0**	**55749.0**	**56887.0**	**57379.0**	**58297.0**	**59454.0**	**64050.0**	**69788.0**	**74308.0**
Interprovincial Transfers (net)	**-2475.0**	**-781.0**	**-1200.0**	**-2200.0**	**-2200.0**	**-2200.0**	**-1900.0**	**-2100.0**	**-1600.0**	**-1900.0**
Exports (Net)	**4668.0**	**4211.0**	**4400.0**	**5000.0**	**5100.0**	**5700.0**	**7000.0**	**3640.0**	**1690.0**	**1940.0**

Yukon
Control Case

Gigawatt hours Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	35.0	9.0	60.0	62.0	63.0	65.0	69.0	94.0	127.0	166.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	405.0	423.0	379.0	379.0	380.0	380.0	383.0	393.0	398.0	400.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Energy Generation	**440.0**	**432.0**	**439.0**	**441.0**	**443.0**	**445.0**	**452.0**	**487.0**	**525.0**	**566.0**
Tot. Domestic Consumption	**440.0**	**432.0**	**439.0**	**441.0**	**443.0**	**445.0**	**452.0**	**487.0**	**525.0**	**566.0**
Interprovincial Transfers (net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Note: The numbers in this table have been rounded.

Table A5-2 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Gigawatt hours — **Northwest Territories Control Case**

Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	20
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Heavy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Natural Gas	90.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Internal Combustion										
-Diesel Oil	211.0	308.0	266.0	275.0	285.0	294.0	304.0	354.0	409.0	468
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Hydroelectric	258.0	256.0	307.0	307.0	307.0	307.0	307.0	307.0	307.0	307
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Total Energy Generation	**559.0**	**564.0**	**573.0**	**582.0**	**592.0**	**601.0**	**611.0**	**661.0**	**716.0**	**775**
Tot. Domestic Consumption	**559.0**	**564.0**	**573.0**	**582.0**	**592.0**	**601.0**	**611.0**	**661.0**	**716.0**	**775**
Interprovincial Transfers (net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0**
Exports (Net)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0**

Gigawatt hours — **British Columbia, Yukon and Northwest Territories Control Case**

Type of Generation	1989	1990	1991	1992	1993	1994	1995	2000	2005	20
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
-Heavy	632.0	434.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500
Natural Gas Fired Steam	5421.0	1776.0	1171.0	1151.0	1484.0	2813.0	5441.0	6213.0	7400.0	8009
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	45.0	70
-Natural Gas	91.0	1.0	0.0	0.0	0.0	0.0	0.0	6.0	43.0	65
Internal Combustion										
-Diesel Oil	488.0	536.0	396.0	407.0	418.0	429.0	443.0	518.0	623.0	732
Nuclear										
Hydroelectric	51056.0	55628.0	56799.0	57537.0	57612.0	57628.0	57613.0	57691.0	60700.0	64505
Other	1416.0	960.0	1095.0	1115.0	1300.0	1473.0	1620.0	1808.0	1808.0	1808
Total Energy Generation	**59104.0**	**59335.0**	**59961.0**	**60710.0**	**61314.0**	**62843.0**	**65617.0**	**66738.0**	**71119.0**	**75689**
Tot. Domestic Consumption	**56911.0**	**55905.0**	**56761.0**	**57910.0**	**58414.0**	**59343.0**	**60517.0**	**65198.0**	**71029.0**	**75649**
Exports (Net)	**4668.0**	**4211.0**	**4400.0**	**5000.0**	**5100.0**	**5700.0**	**7000.0**	**3640.0**	**1690.0**	**1940**

Note: The numbers in this table have been rounded.

Table A5-3
Fuel Requirements for Electricity Generation - Canada

Petajoules

	Control Case									
	1989	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Coal[a]										
-Bituminous	405.0	342.2	259.8	245.1	250.2	279.4	352.4	499.6	629.4	670.0
-Sub-Bituminous	417.3	394.9	450.4	463.0	467.8	471.3	471.6	501.6	521.0	552.8
-Lignite	143.3	111.0	107.3	107.7	112.4	119.8	114.6	124.4	118.6	127.0
-Total Coal	965.6	848.1	817.5	815.8	830.4	870.5	938.6	1,125.6	1,269.0	1,349.8
Oil[a]										
-Light	2.9	2.4	1.7	1.3	1.7	2.7	4.2	1.6	3.9	13.9
-Heavy	163.3	146.4	101.5	97.6	101.8	102.1	82.6	75.6	85.8	106.4
-Diesel	11.0	10.5	12.7	12.8	13.0	13.1	13.2	13.9	15.2	16.4
-Total Oil	177.2	159.3	116.0	111.6	116.5	117.9	99.9	91.1	104.9	136.7
Natural Gas[a]	145.9	89.9	56.3	58.6	65.1	85.3	122.2	137.7	165.5	176.7
Uranium[b]	911.7	832.9	1,090.5	1,211.7	1,332.9	1,332.9	1,332.9	1,267.8	1,224.1	1,370.7
Hydroelectric[c]	1,035.9	1,056.7	1,078.7	1,136.0	1,170.4	1,211.0	1,236.3	1,299.3	1,408.3	1,484.7
Other [d]	33.9	25.3	31.0	33.2	37.6	39.8	42.4	45.7	46.1	46.8
Total Energy Generation	**3,270.2**	**3,012.2**	**3,190.0**	**3,366.9**	**3,552.9**	**3,657.4**	**3,772.3**	**3,967.2**	**4,217.9**	**4,565.4**

Notes: The numbers in this table have been rounded.

[a] Converted to petajoules from thermal generation based on plant specific factors. The numbers shown in this Table and Table A6-11 and A10-1 differ slightly because final adjustments were made to electricity supply.

[b] Converted to petajoules from nuclear generation based on a rate of 12.1 PJ/TW.h.

[c] Converted to petajoules from hydro generation based on a rate of 3.6 PJ/TW.h.

[d] Other includes electricity production from forest wastes, industrial fuels such as blast furnace gas, as well as minor sources of production such as wind, solar, etc.

Table A5-4
Net Electricity Exports and Transfers
Canada and Provinces (GWh) [a]

Historical

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Newfoundland	84	260	6401	13888	22228	29597	32106	33350	37024	35290
Prince Edward Island	0	0	0	0	0	0	0	-67	-269	-361
Nova Scotia	-195	-7	-143	-178	-156	-199	-334	-376	-224	-351
New Brunswick	920	1063	790	463	-873	-2035	-1015	248	-550	983
Quebec	6148	5500	260	-1793	-7321	-13824	-16544	-18681	-23876	-18859
Ontario	-5632	-4411	-4059	-4260	-6158	-10640	-8724	-2709	663	4784
Manitoba	-319	424	899	1405	2898	2893	1899	302	4244	6360
Saskatchewan	777	518	425	372	90	-97	37	208	38	-474
Alberta	155	151	143	3	-18	-146	-316	252	50	286
British Columbia	464	130	889	4727	2267	1853	2104	4741	2412	1920
Canada	**2402**	**3628**	**5605**	**14627**	**12957**	**7402**	**9213**	**17268**	**19512**	**29578**

Historical

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Newfoundland	37829	35941	35779	31229	36012	31836	30696	30393	30702	24368
Prince Edward Island	-388	-480	-478	-520	-550	-585	-595	-591	-606	-622
Nova Scotia	54	-192	-83	616	-32	-169	-540	-577	-19	-100
New Brunswick	485	147	-95	2408	1881	886	667	595	3234	4398
Quebec	-20336	-17481	-17923	-11714	-13132	-7733	-3700	-1593	-14298	-17963
Ontario	3775	3367	3988	5570	2223	-677	-1764	-626	2195	-5794
Manitoba	5541	4902	6516	7318	6246	6864	7837	3926	-744	1186
Saskatchewan	-624	-248	-390	-402	-272	-211	-48	-13	-331	-134
Alberta	26	91	-259	-122	-43	137	57	462	876	2258
British Columbia	631	7828	4307	2499	6759	9974	1367	11851	6825	2193
Canada	**26993**	**33875**	**31362**	**36882**	**39092**	**40322**	**33977**	**43827**	**27834**	**9790**

Projected
Control Case

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Newfoundland	24368	26164	31085	31085	31085	31757	31085	32241	37316	37085
Prince Edward Island	-622	-672	-668	-678	-698	-620	-616	-686	-776	-876
Nova Scotia	-100	-249	0	0	0	-560	0	0	0	0
New Brunswick	4398	3491	2312	2332	2152	-1296	3147	3256	2298	2677
Quebec	-17963	-21849	-25217	-17271	-14041	-7238	-5110	-8493	-8188	-10187
Ontario	-5794	-13475	-7654	-2104	5592	3027	3859	2349	-759	-759
Manitoba	1186	2699	3049	6982	9468	979	9658	10083	13316	13316
Saskatchewan	-134	-48	-652	-672	-672	33	-612	-72	-1072	-1072
Alberta	2258	833	1245	2265	2265	199	1965	2165	1665	1965
British Columbia	2193	3456	3200	2800	2900	7000	5100	1540	90	40
Canada	**9790**	**350**	**6700**	**24739**	**38051**	**33281**	**48476**	**42383**	**43890**	**42189**

Notes: The numbers in this table have been rounded.

[a] Net Exports and Transfers represent the arithmetic sum of all inflows and outflows where inflows are negative and outflows are positive. Here net outflows are shown as positive.

Table A5-5

Gross Electricity Exports - Canada and Provinces

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Control Case										
Gigawatt hours [a]										
New Brunswick	4454	4185	3693	4003	4003	4303	5080	2619	1881	1855
Quebec	5706	5098	4380	11026	13956	19056	22154	22927	27897	25977
Ontario	2714	738	2116	4666	7502	7502	7502	7502	7202	7202
Manitoba	1228	1932	2040	5103	7589	8589	7839	5794	5319	5319
Saskatchewan	10	60	88	88	88	88	88	88	88	88
British Columbia	4350	4481	4400	5000	5100	5700	7000	6400	6400	6400
Canada	**18462**	**16494**	**16717**	**29886**	**38238**	**45238**	**49663**	**45330**	**48787**	**46841**
Petajoules [b]										
New Brunswick	54.2	42.3	37.9	39.3	39.3	44.0	52.3	42.9	40.8	40.5
Quebec	20.5	18.4	15.8	39.7	50.2	68.6	79.8	82.5	100.4	93.5
Ontario	22.2	7.8	22.6	55.1	80.1	80.1	80.1	80.1	74.1	74.4
Manitoba	4.4	7.0	7.3	18.3	27.3	30.9	28.2	20.9	19.1	19.1
Saskatchewan	0.1	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
British Columbia	29.3	30.0	27.4	37.3	37.6	40.3	44.5	37.7	37.7	37.7
Canada	**130.7**	**106.1**	**112.0**	**190.7**	**235.5**	**264.9**	**285.9**	**265.1**	**273.1**	**266.2**

Notes: The numbers in this table have been rounded

[a] Excludes exchanges

[b] Converted from gigawatt hours using plant specific factors for fossil fuels, and 3.6 PJ/TW.h for hydro and 12.1 PJ/TW.h for nuclear

Table A5-6
Gross Electricity Exports by Fuel Type - Canada

Terawatt hours

Control Case [a]

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Hydro	9.9	8.1	9.6	19.0	24.5	31.4	35.0	32.3	38.1	35.1
Coal	2.6	4.4	4.2	7.3	10.2	10.6	11.4	10.3	8.3	9.7
Nuclear	2.0	2.3	1.9	2.4	2.3	2.0	1.9	1.5	1.5	1.5
Oil	1.4	0.9	1.0	1.2	1.2	1.2	1.4	1.2	0.9	0.5
Natural Gas	2.6	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**18.5**	**16.5**	**16.7**	**29.9**	**38.2**	**45.2**	**49.7**	**45.3**	**48.8**	**46.8**

Notes: The numbers in this table have been rounded.
[a] Excludes exchanges

Appendix 6
Table A6-1
Historical Data
Established Reserves and Cumulative Production of Marketable Natural Gas

(Exajoules)

	Initial Reserves	Cumulative Production	Remaining Reserves
1967	64.8	10.6	54.2
1968	67.9	12.0	55.8
1969	74.8	13.9	60.8
1970	77.1	15.7	61.4
1971	82.9	18.3	64.6
1972	83.2	20.8	62.4
1973	87.4	23.5	63.9
1974	89.2	26.2	63.0
1975	91.1	28.9	62.2
1976	96.3	31.4	64.9
1977	102.7	34.3	68.5
1978	110.9	36.9	74.1
1979	115.9	40.0	75.9
1980	119.2	42.8	76.4
1981	126.5	45.7	80.8
1982	130.0	48.5	81.5
1983	131.3	51.3	80.0
1984	132.9	54.3	78.6
1985	134.8	57.4	77.3
1986	136.0	60.8	75.3
1987	135.5	63.5	72.0
1988	137.8	67.1	70.6
1989	157.2	71.4	85.8

Source: National Energy Board

Table A6-2
Net Incremental Direct Costs for Natural Gas
Western Canada

($C 1990 per Gigajoule)

Reserves Additions Increment (EJ)	Control case (a)	Control case (b)	Low Resource Case (b)	High Resource Case (b)
0-5	0.95	1.44	1.51	1.41
5 - 10	0.99	1.49	1.61	1.45
10 - 15	1.03	1.55	1.72	1.49
15 - 20	1.08	1.62	1.86	1.53
20 - 25	1.13	1.68	2.01	1.57
25 - 30	1.18	1.76	2.19	1.62
30 - 35	1.24	1.84	2.39	1.67
35 - 40	1.30	1.93	2.64	1.73
40 - 45	1.37	2.02	2.94	1.78
45 - 50	1.44	2.13		1.84
50 - 55	1.52	2.24		1.90
55 - 60	1.60	2.37		1.97
60 - 65	1.70	2.51		2.04
65 - 70	1.80	2.66		2.12
70 - 75	1.91	2.84		2.20
75 - 80	2.03	3.03		2.27
80 - 85	2.17	3.26		2.38
85 - 90	2.33	3.52		2.48
90 - 95	2.50	3.82		2.58
95 - 100				2.70
105 - 110				2.82
110 - 115				2.96
115 - 120				3.10
120 - 125				3.27
125 - 130				3.45
130 - 135				3.65
135 - 140				3.87
140 - 145				4.13
145 - 150				4.44

Note: 1. Net incremental direct costs includes credit for by-products.
2. Costs are projected for reserves additions to within 10EJ of the ultimate potential.

(a) Excluding rate of return to producer.
(b) Including rate of return to producer for connection rate schedule 2 of Table A6-11.

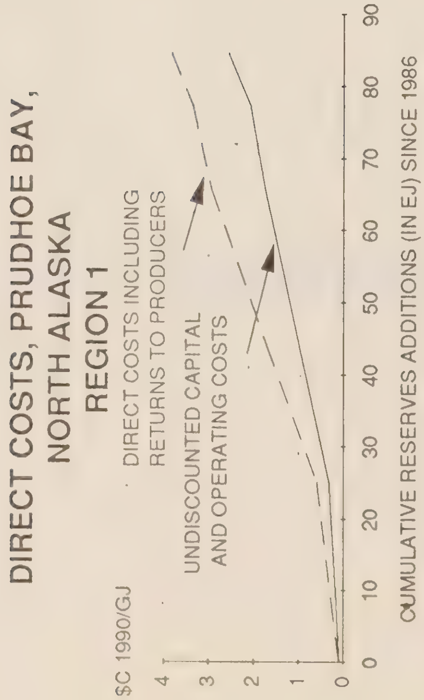
Table A6-3
Control Case
United States Natural Gas Resource Estimates
Disaggregated by NARG Region

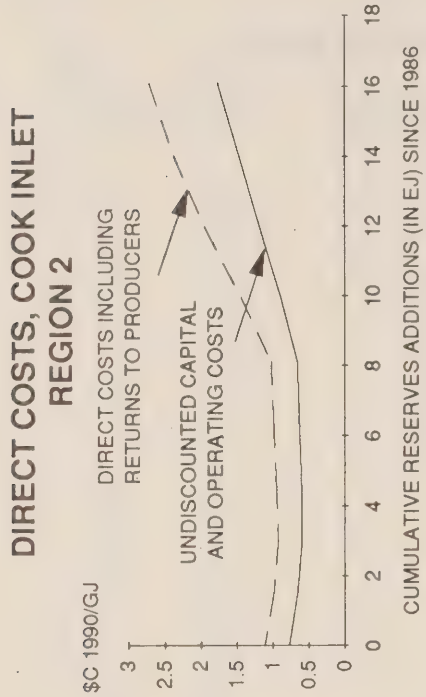
(TCF)		PGC "Most Likely" Resource Estimates				NEB Control Case [a]	NEB Maximum Case [a]
NARG #	**Supply Area**	**Probable**	**Possible**	**Speculative**	**Total**		
1	North Alaska Onshore	6	15	24	44	44	44
2	Cook Inlet	1	2	3	7	7	7
18	Beaufort Sea	2	12	40	54	54	54
19	South Alaska	0	0	14	14	14	14
	Total Alaska	**9**	**29**	**81**	**119**	**119**	**119**
43 ,62	California Onshore	2	5	3	10	10	28
39	S California Offshore	0	5	2	7	7	10
3	San Juan Basin	2	1	0	2	2	3
6	Rocky Mountain Deep	14	21	7	42	42	54
4	Rocky Mountain	25	30	10	65	65	93
7	Northern Great Plains	3	3	4	11	11	12
10	West Texas JS	6	19	1	26	26	39
40	West Texas JS Deep	8	14	0	21	21	29
29 ,74	Anadarko JN	21	18	24	62	70	94
9	Anadarko JN Deep	9	10	6	24	24	46
14	Midwest C	2	7	10	19	16	42
16	Appalachian A	22	8	18	47	47	113
42	Appalachian Deep	0	0	10	10	10	28
37	Atlantic Offshore	0	0	13	13	0	0
46	S E Gulf B	3	2	2	7	7	10
11	S E Louisiana	3	2	0	5	5	5
45	Arkoma D	6	6	2	14	14	17
44	South Texas G	3	9	1	13	13	13
41	Gulf Deep BDEG	11	20	15	46	46	58
12	Offshore Gulf EGO	25	36	9	71	71	103
47	Deep Offshore	2	19	10	31	31	51
	> 1000 metres WD	0	0	30	30	10	10
	Total Lower 48 States	**164**	**233**	**177**	**574**	**546**	**856**

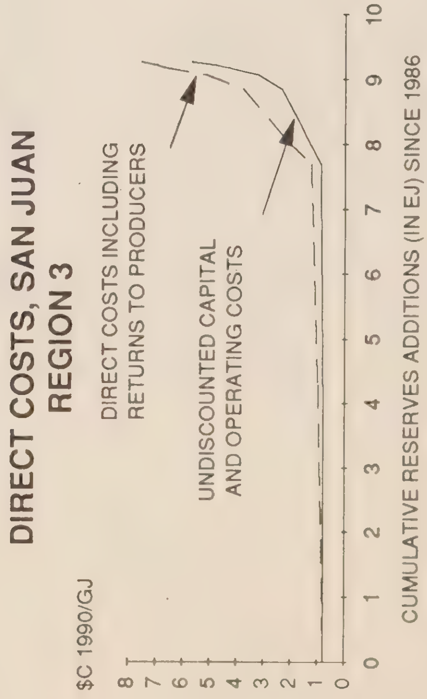
[a]The regional estimates for the Lower-48 States used in the NARG model differ somewhat from those reported elsewhere in the report due to certain modest adjustments made to facilitate the preparation of the model input data.

Note : The numbers in this table have been rounded.

Table A6-4
Direct Cost Estimates for NARG Supply Regions







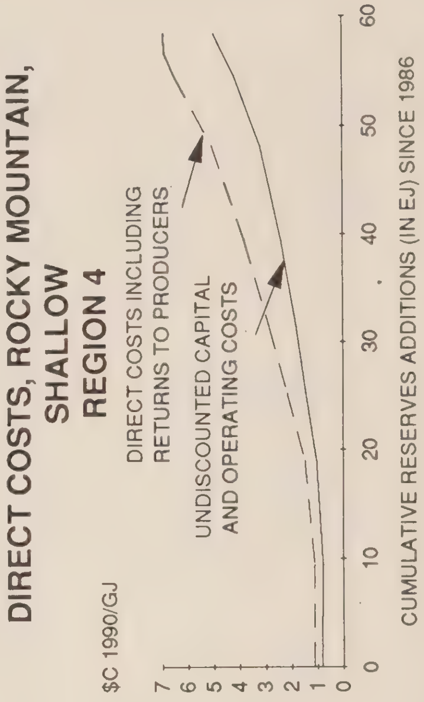
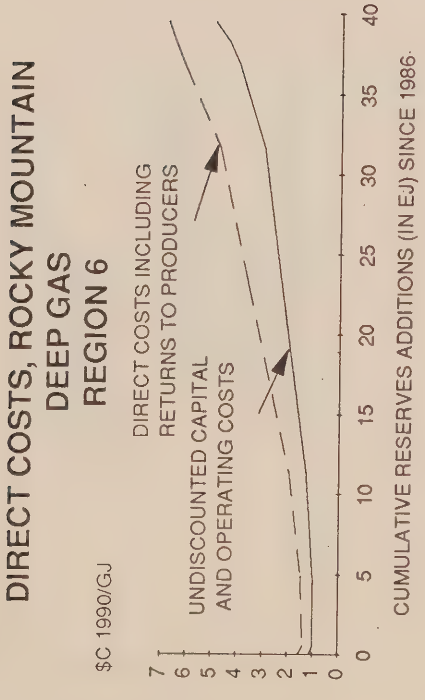
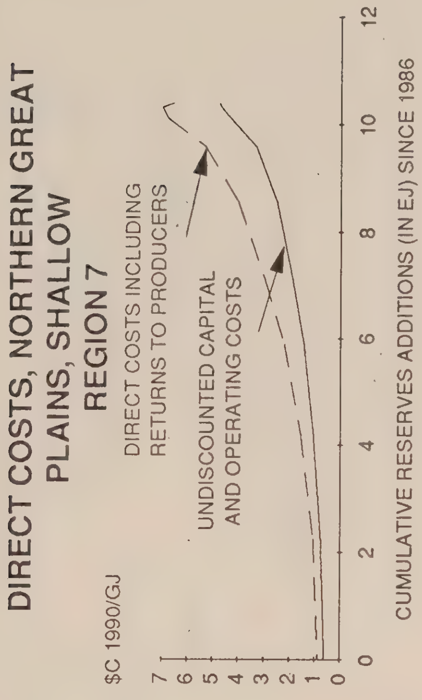
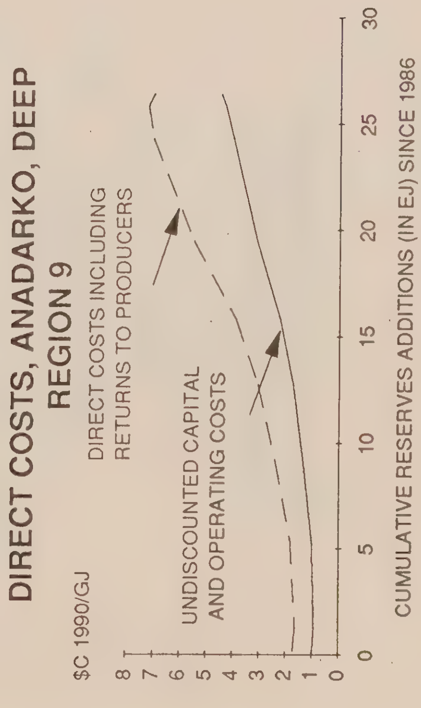


Table A6-4
Direct Cost Estimates for NARG Supply Regions (Continued)







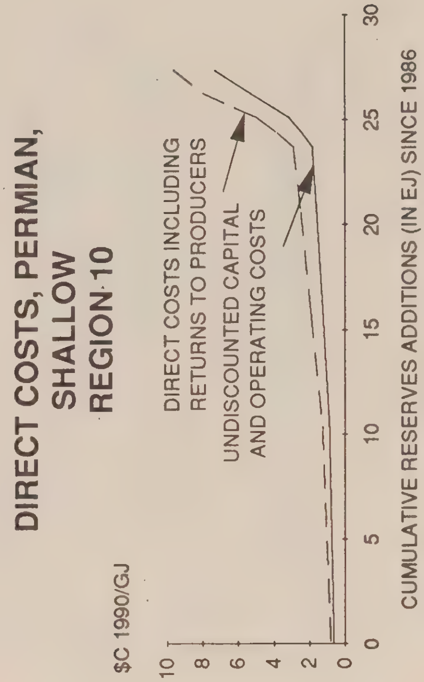
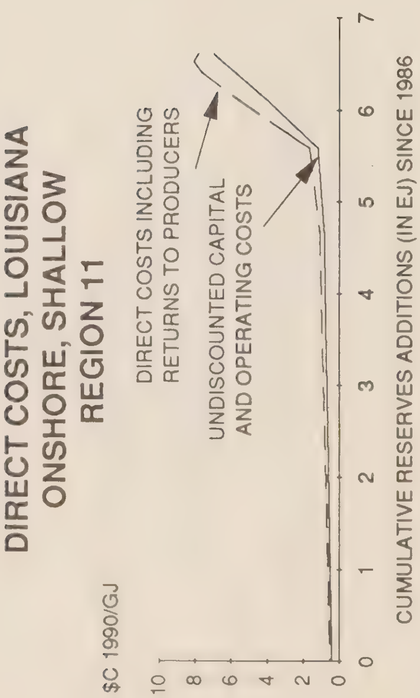
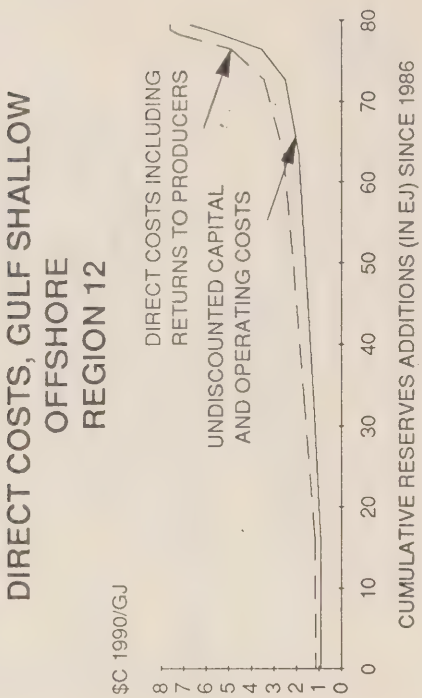
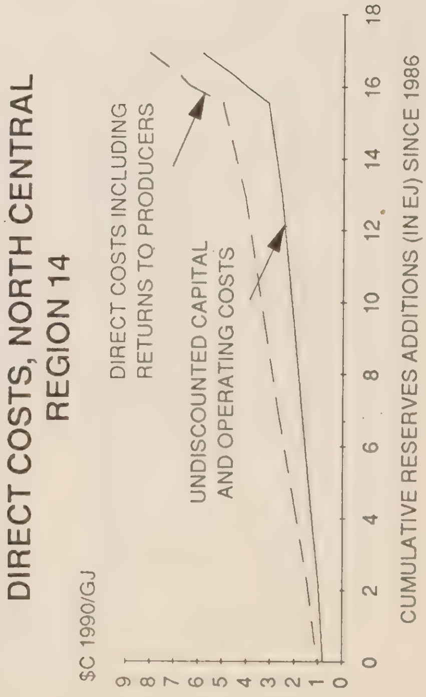
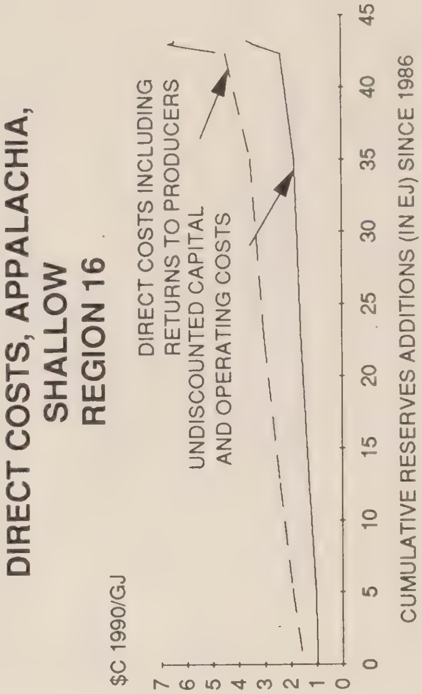


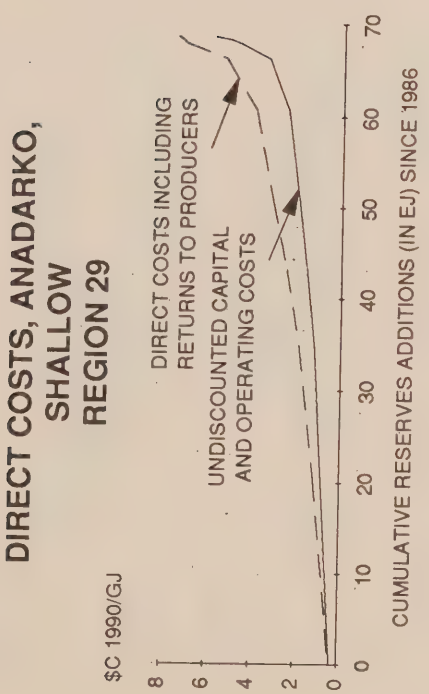
Table A6-4
Direct Cost Estimates for NARG Supply Regions (Continued)

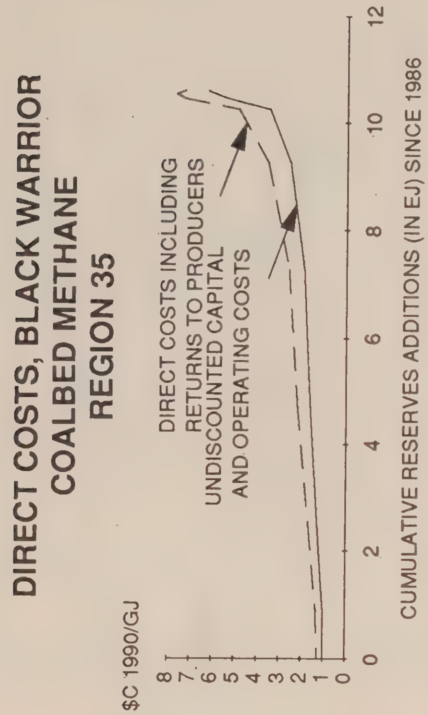


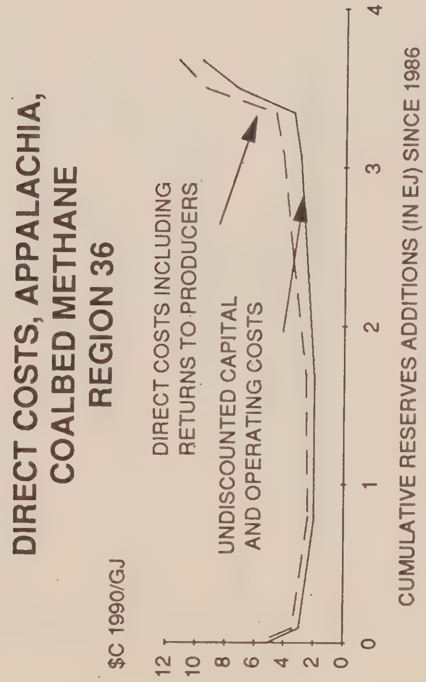







DIRECT COSTS, ANADARKO, SHALLOW
REGION 29
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986


DIRECT COSTS, BLACK WARRIOR COALBED METHANE
REGION 35
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986


DIRECT COSTS, APPALACHIA, COALBED METHANE
REGION 36
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986

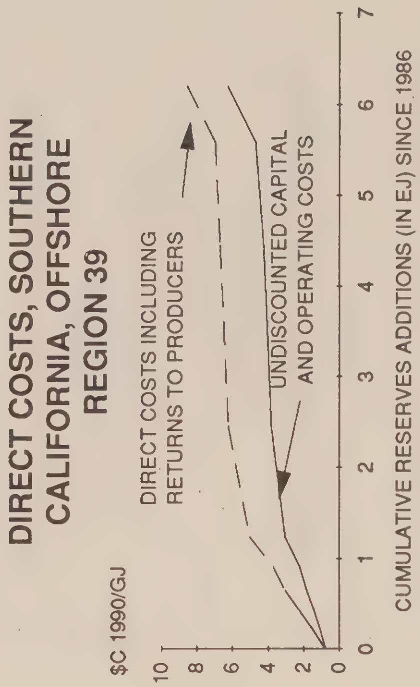
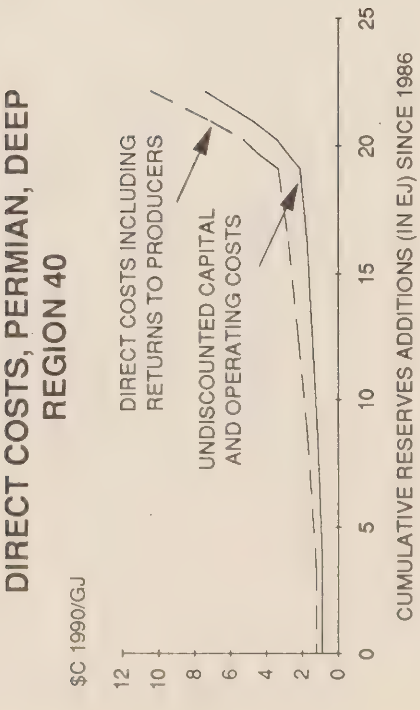
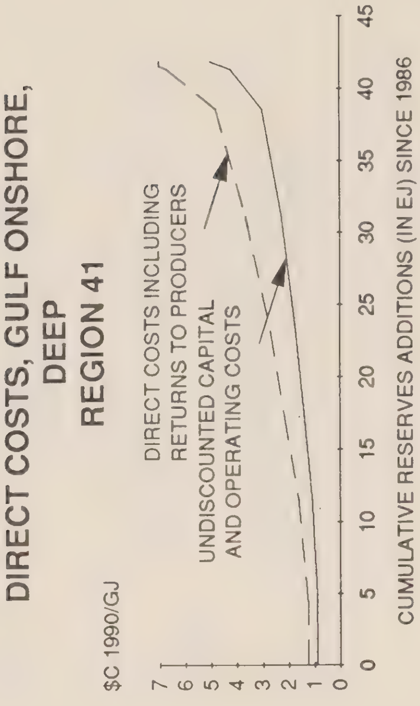
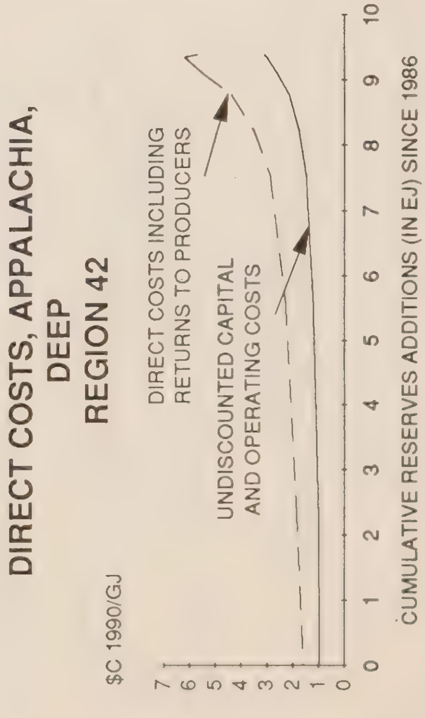
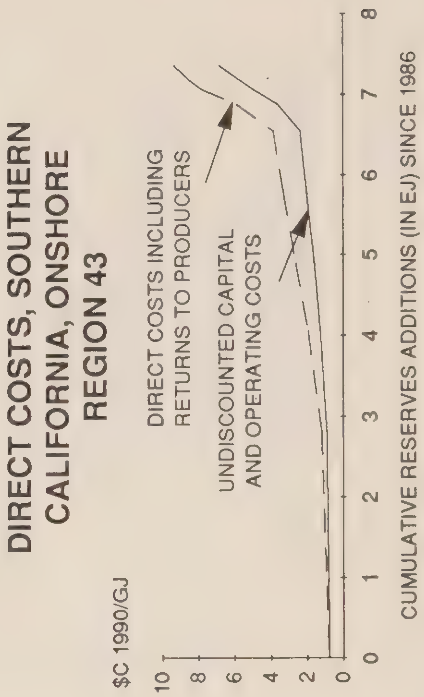

DIRECT COSTS, SOUTHERN CALIFORNIA, OFFSHORE
REGION 39
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986

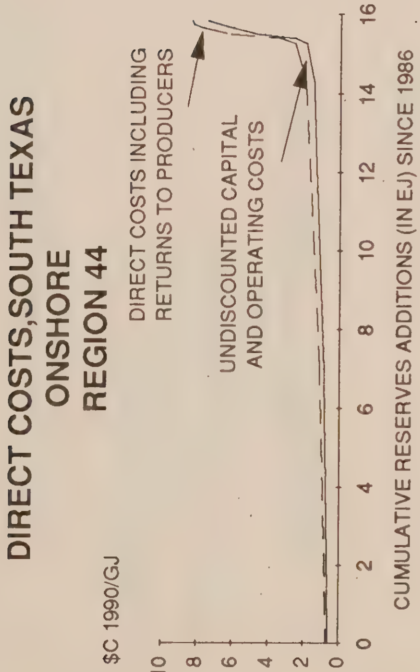
Table A6-4
Direct Cost Estimates for NARG Supply Regions (Continued)










DIRECT COSTS,SOUTH TEXAS ONSHORE
REGION 44
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
10
8
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2
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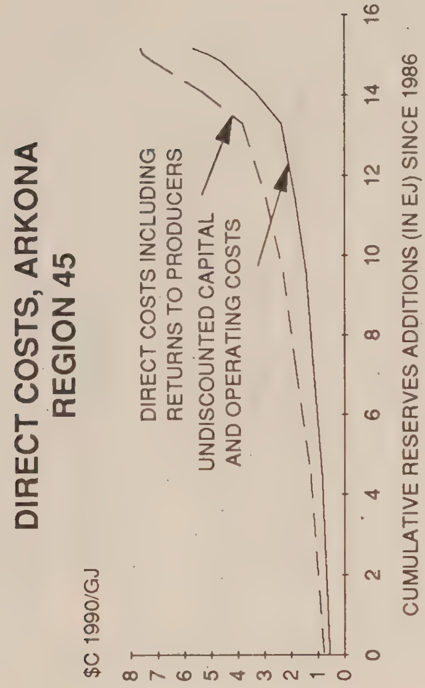
0
2
4
6
8
10
12
14
16
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986


DIRECT COSTS, ARKONA
REGION 45
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
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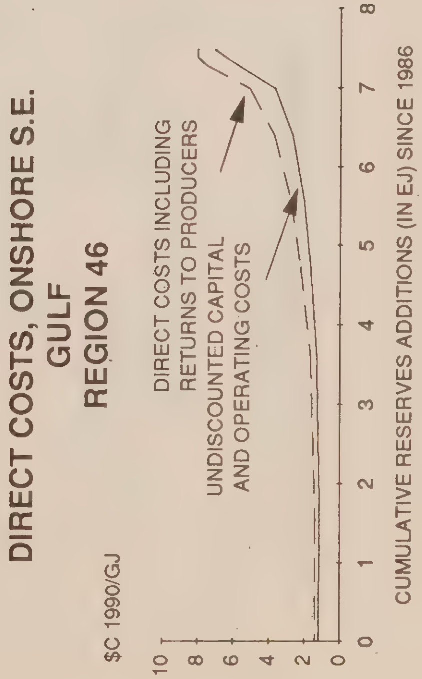
16
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986


DIRECT COSTS, ONSHORE S.E. GULF
REGION 46
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
10
8
6
4
2
0
0
1
2
3
4
5
6
7
8
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986

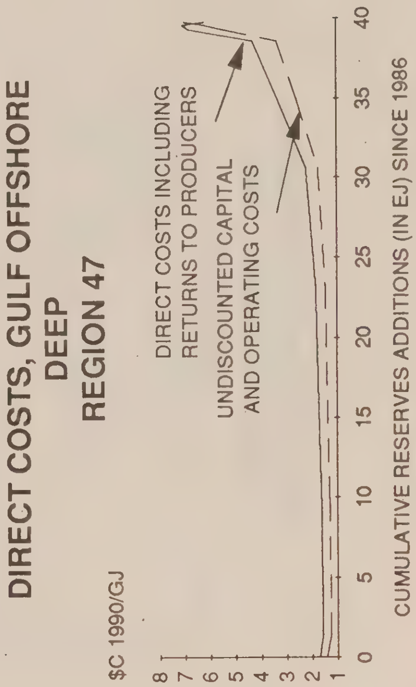
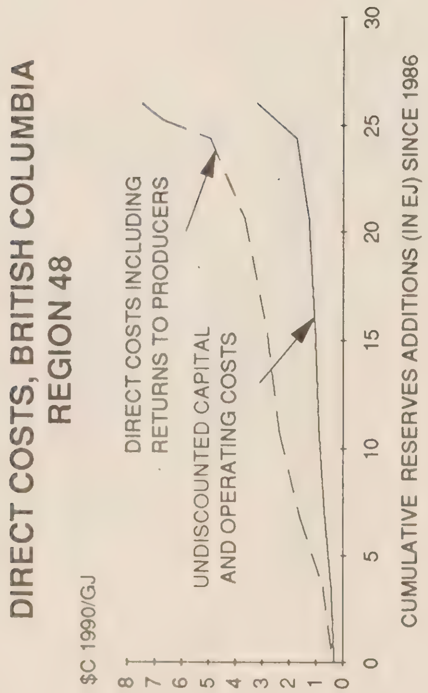
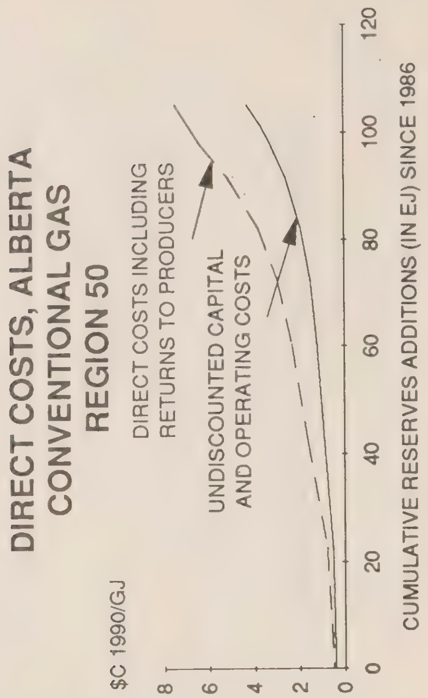
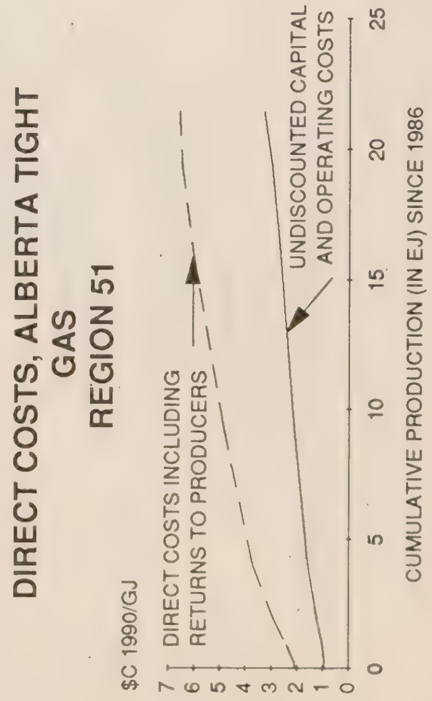
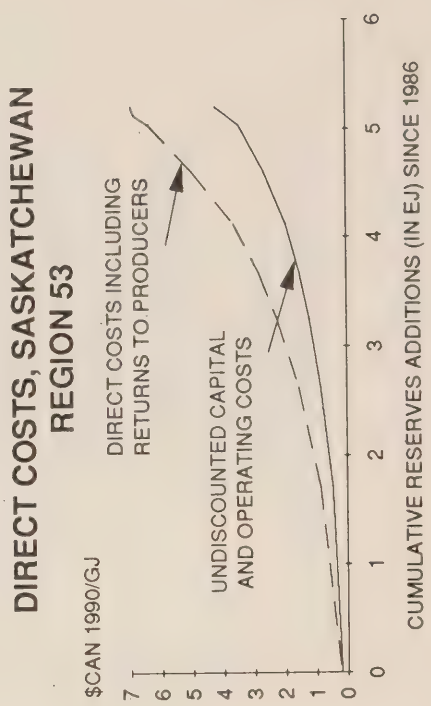

DIRECT COSTS, GULF OFFSHORE DEEP
REGION 47
$C 1990/GJ
DIRECT COSTS INCLUDING RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL AND OPERATING COSTS
8
7
6
5
4
3
2
1
0
5
10
15
20
25
30
35
40
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986

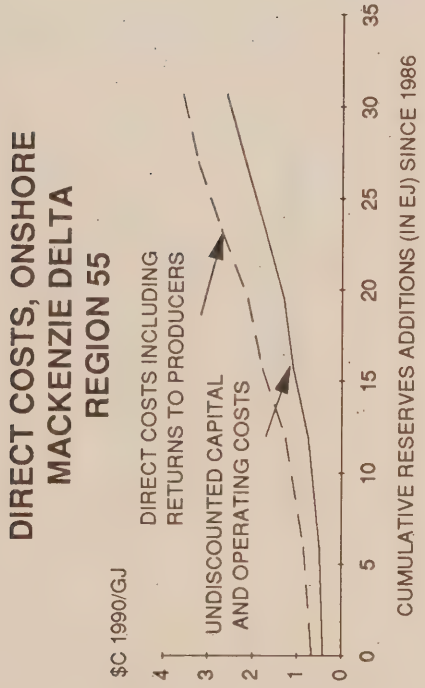
Table A6-4
Direct Cost Estimates for NARG Supply Regions (Continued)










DIRECT COSTS, ONSHORE
MACKENZIE DELTA
REGION 55
$C 1990/GJ
DIRECT COSTS INCLUDING
RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL
AND OPERATING COSTS
0
1
2
3
4
0
5
10
15
20
25
30
35
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986

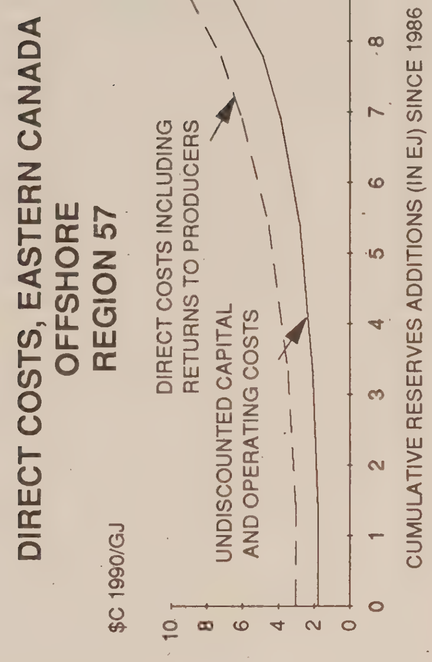
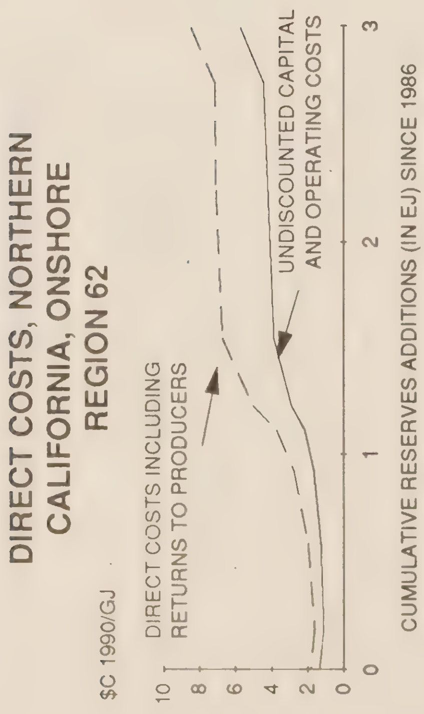
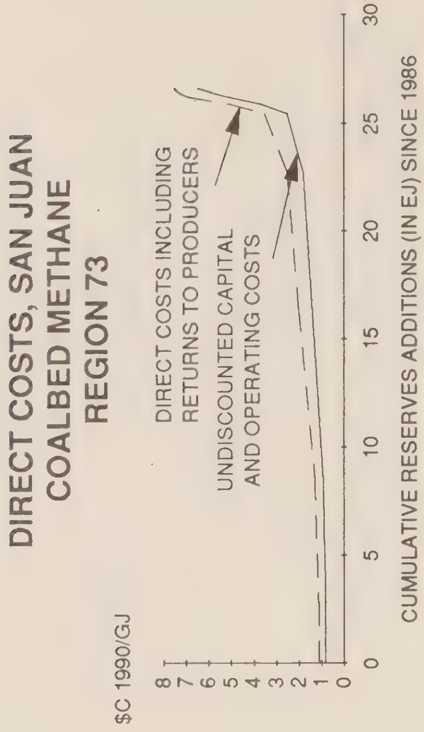

DIRECT COSTS, EASTERN CANADA
OFFSHORE
REGION 57
$C 1990/GJ
DIRECT COSTS INCLUDING
RETURNS TO PRODUCERS
UNDISCOUNTED CAPITAL
AND OPERATING COSTS
0
2
4
6
8
10
0
1
2
3
4
5
6
7
8
9
CUMULATIVE RESERVES ADDITIONS (IN EJ) SINCE 1986

Table A6-4
Direct Cost Estimates for NARG Supply Regions (Continued)





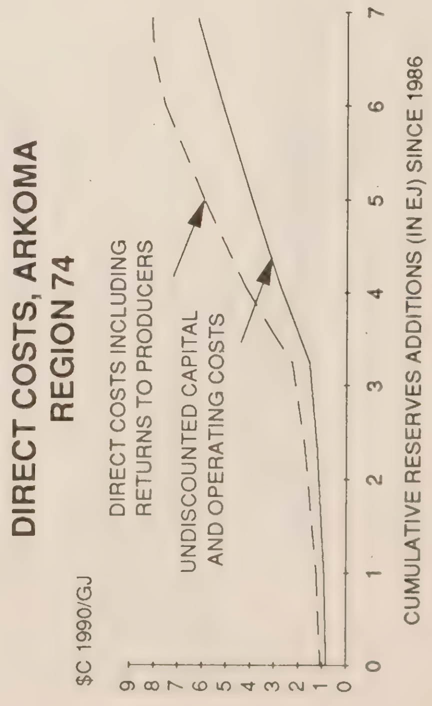


Table A6-5
Control Case - Composition of Pipeline Corridors

No.[a]	Pipeline Corridor	Constituent Pipelines[b]
1	ANGTS to Alberta	(Alaska Natural Gas Transportation System, 1996)
2	North to South Alaska	(Trans-Alaska Gas System, 1996)
3	South Alaska to Japan	Yukon Pacific LNG
4	San Juan to S. California	El Paso - North Leg + Southern California Gas Co., (Transwestern - San Juan Lateral, 1993)
5	San Juan to N. California	El Paso - North Leg + PG&E
6	San Juan to EOR (Mojave)	El Paso North Leg + (Mojave Pipeline, 1993)
7	San Juan to Rocky Mountains	Northwest Pipeline[c]
8	San Juan to West North Central	El Paso - North Leg, Public Service of New Mexico Gas Co., Western Gas Supply
9	San Juan to Permian Basin	(El Paso, 1992)
10	Rockies to San Juan	Northwest Pipeline[c], (TransColorado Project, 1992)
11	Rockies to West North Central	KN Energy, Colorado Interstate, Overthrust, Wyoming Interstate, Questar
12	Rockies to Northern Great Plains	(Unnamed, 2000)
13	Rockies to Anadarko	Williams Natural Gas, Colorado Interstate Gas Company
14	Rockies to EOR	(Kern River Pipeline,1992)
15	Rockies to Pacific Norhtwest	Northwest Pipeline
16	Rockies to California Border	Northwest Pipeline + (PGT Loop, 1993)
17	Northern Great Plains to East North Central	(Unnamed, 2017)
18	Northern Great Plains to West North Central	Williston Basin Pipeline
19	Anadarko to West North Central	KN Energy, ANR Pipeline Co., Northern Natural Gas, Williams Natural Gas, Panhandle Eastern Pipe Line, Colorado Interstate Gas Company
20	Anadarko to East North Central	ANR Pipeline Company, Natural Gas Pipeline Company of America, Northern Natural Gas, Panhandle Eastern Pipe Line
21	Anadarko to Permian Basin	El Paso, Transwestern, Red River , Westar Transmission, Palo Duro
22	Anadarko to West South Central	Various Texas & Oklahoma Intrastate Pipelines
23	Anadarko to Gulf Coast	Seagas Pipeline, Texoma Pipeline
24	Anadarko to Permian	El Paso
25	Anadarko to Permian	Transwestern
26	Arkoma to Anadarko	Arkansas-Oklahoma Gas, Ozark Gas Transmission System
27	Arkoma to East South Central	(Panhandle Eastern, Oklahoma-Arkansas Pipeline, Arkla, 1992)

[a] Numbers correspond to pipeline corridor numbers in Figure 6-2.
[b] Proposed pipelines in brackets
[c] Bi-directional

Table A6-5 (Continued)
Control Case - Composition of Pipeline Corridors

No.	Pipeline Corridor	Constituent Pipelines
28	Permian Basin to Anadarko	Natural Gas Pipeline Company of America:Northern Natural Gas
29	Permian Basin to West North Central	El Paso - South Leg, Transwestern
30	Permian Basin to West South Central	Various Texas Intrastate Pipelines
31	Permian Basin to San Juan	El Paso - North Leg
32	Permian Basin to S. California	El Paso - South Leg
33	Permian Basin to S. California	Transwestern
34	Permian Basin to Gulf Coast	Lone Star[c], Oasis, Valero - North Leg+South Leg[c]
35	Gulf Coast to West South Central	Black Marlin, Gulf, Houston Pipeline, Valero, ANR Pipeline, Natural Gas Pipeline Company of America, Sea Robin, Southern Natural Gas Co., Stingray, Tennessee Gas Pipeline, Texas Eastern Transmission, Texas Gas Transmission, Transcontinental Gas Pipe Line, Trunkline Gas Company, United Gas Pipe Line, Florida Gas Transmission, Mississippi River Transmission, Arkla, United Texas Transmission Co., Exxon Gas Supply, TransAmerican, Channel, Delhi, High Island Offshore System, Lone Star, Various Texas Intrastate Pipelines
36	Gulf Coast to Permian Basin	Lone Star[c], Valero - South Leg[c]
37	Gulf Coast to East South Central	Columbia Gulf Transmission, Florida Gas Transmission, Southern Natural Gas Co., Transcontinental Gas Pipe Line, United Gas Pipeline, Tennessee Gas Pipeline, ANR Pipeline Co., Trunkline Gas Co., Texas Gas Transmission, Texas Eastern Transmission, Mississippi River Transmission, Natural Gas Pipeline Company of America
38	North Central to East North Central	Various Ohio, Michigan and Illinois Intrastate Pipelines
39	West North Central to East North Central	Trailblazer + Natural Gas Pipeline of America/Northern Natural Gas
40	East North Central to Mid-Atlantic	(Trunkline Gas Co., Columbia Gas Transmission, Texas Eastern Transmission, CNG Transmission, 1992)
41	East North Central to Ontario	Panhandle, ANR, St.Clair

[c] Bi-directional

Table A6-5 (Continued)
Control Case - Composition of Pipeline Corridors

No.	Pipeline Corridor	Constituent Pipelines
42	East South Central to East North Central	ANR Pipeline Co., Natural Gas Pipeline Co. of America, Texas Eastern Transmission, Texas Gas Transmission, Trunkline Gas Co., Midwestern Gas Transmission, Mississippi River Transmission
43	East South Central to South Atlantic	Florida Gas Transmission, United Gas Pipe Line, Transcontinental Gas PipeLine, Southern Natural Gas Co. Columbia Gas Transmission,
44	East South Central to Mid-Atlantic	Texas Eastern Transmission, Tennessee Gas Pipeline, CNG Transmission
45	Appalachia to South Atlantic	East Tennessee, Tennessee Gas Pipeline Columbia Gas Transmission, CNG Transmission
46	Appalachia to Mid-Atlantic	CNG Transmission, Columbia Gas Transmission, Equitable
47	South Atlantic to Mid-Atlantic	Columbia Gas Transmission, Transcontinental Gas Pipe Line
48	Mid-Atlantic to New England	Algonquin, Tennessee Gas Pipeline
49	Pacific Northwest to California Border	Northwest Pipeline + (PGT Loop, 1993)
50	Pacific Northwest to Rockies	Northwest Pipeline
51	California Border to S. California	(Pacific Gas & Electric Expansion, 1993)
52	California Border to N. California	Pacific Gas & Electric, (Pacific Gas & Electric Expansion, 1993)
53	S. California to SOCALGAS Co.	Southern California Gas Co.
54	S. California to SDG&E	Southern California Gas Co.
55	S. California to EOR	Southern California Gas Co.
56	SOCALGAS Co. to EOR	Southern California Gas Co.
57	N. California to PG&E	Pacific Gas and Electric
58	PG&E to EOR	Pacific Gas and Electric
59	EOR to N. California	(Pacific Gas and Electric, 1992)
60	EOR to S. California	(Southern California Gas Co., 1992)
61	Offshore Atlantic to South Atlantic	(Unnamed, 1995)
62	Offshore Atlantic to Mid-Atlantic	(Unnamed, 1995)
63	Mexico to Gulf Coast	Petroleos Mexicanos, Texas Eastern Transmission

Table A6-5 (Continued)
Control Case - Composition of Pipeline Corridors

No.	Pipeline Corridor	Constituent Pipelines
64	LNG to Gulf Coast	Trunkline LNG
65	LNG to South Atlantic	Columbia LNG, Southern Energy Co.
66	LNG to New England	Distrigas
67	Huntingdon to Pacific Northwest	Northwest Pipeline, Ferndale Pipeline
68	South Alberta to California Border	Pacific Gas Transmission, (PGT Loop, 1993)
69	South Alberta to Pacific Northwest	Northwest Pipeline - via PGT & PITCO
70	South Alberta to West North Central	Montana Power Co.
71	South Alberta to Rockies	(Altamont, 1993)
72	Monchy to West North Central	Northern Border Pipeline, (Northern Border Expansion, 1992)
73	Monchy to East North Central	Northern Border Pipeline, (Northern Border Extension, 1992)
74	Emerson to East North Central	Great Lakes, Midwestern Gas Transmission
75	New York Border to Mid-Atlantic	Niagra, St. Lawrence Gas, Portland Pipeline, Vermont Gas System
76	New York Border to Mid-Atlantic	Iroquois
77	Scotian Shelf to New England	(Venture Project, 2000)
78	BC to BC Demand	Westcoast Transmission
79	BC to Huntingdon	Westcoast Transmission
80	BC to Alberta	Westcoast Transmission
81	Alberta to BC	Westcoast Transmission
82	Alberta to Western Canada	NOVA, Canadian Western, NW Utilities Ltd.
83	Alberta to Monchy	NOVA + Foothills - East Leg
84	Alberta to Saskatchewan	NOVA + TransCanada, NOVA + Saskatchewan Power
85	Alberta to South Alberta	NOVA + Foothills - West Leg
86	Northern Canada to Alberta	(MacKenzie Valley Pipeline, 1996)
87	Saskatchewan to Western Canada	Saskatchewan Power
88	Saskatchewan to Ontario	TransCanada Pipelines
89	Saskatchewan to Emerson	TransCanada Pipelines
90	Ontario to Eastern Canada	TransCanada Pipelines
91	Ontario to New York Border	TransCanada Pipelines

Table A6-6
Control Case - Pipeline Corridor Input Data

No.[a]	Corridor Name	Toll ($ C 1990/GJ)	Proposed Pipeline Year of Commercial Availability
1	ANGTS to Alberta	2.81	1996
2	North to South Alaska	2.23	1996
3	South Alaska to Japan	2.11	
4	San Juan to S. California	0.32	
5	San Juan to N. California	0.32	
6	San Juan to EOR (Mojave)	0.43	1993
7	San Juan to Rocky Mountains	0.31	
8	San Juan to West North Central[b]	0.27	
9	San Juan to Permian Basin	0.42	1993
10	Rockies to San Juan	0.31	
11	Rockies to West North Central	0.30	
12	Rockies to Northern Great Plains	1.76[c]	2000
13	Rockies to Anadarko	0.57	
14	Rockies to EOR	0.62	1993
15	Rockies to Pacific Northwest	0.26	
16	Rockies to California Border	0.38	1993
17	Northern Great Plains to East North Central	1.55[c]	2017
18	Northern Great Plains to West North Central	0.38	
19	Anadarko to West North Central	0.42	
20	Anadarko to East North Central	0.42	
21	Anadarko to Permian Basin	0.29	
22	Anadarko to West South Central	0.15	
23	Anadarko to Gulf Coast	0.15	
24	Anadarko to Permian (El Paso)	0.06	
25	Anadarko to Permian (Transwestern)	0.06	
26	Arkoma to Anadarko	0.06	
27	Arkoma to East South Central	0.31	1992
28	Permian Basin to Anadarko	0.12	
29	Permian Basin to West North Central	0.16	
30	Permian Basin to West South Central	0.12	
31	Permian Basin to San Juan	0.16	
32	Permian Basin to S. California (El Paso)	0.37	
33	Permian Basin to S. California (Transwestern)	0.37	
34	Permian Basin to Gulf Coast	0.31	
35	Gulf Coast to West South Central	0.31	
36	Gufl Caost to Permian Basin	0.31	
37	Gulf Coast to East South Central	0.25	

[a] Numbers correspond to pipeline corridor numbers in Figure 6-2.
[b] Maximum flows on this pipeline corridor have been specified at .18 Tcf/yr.
[c] This toll is calculated endogenously according to capital costs and operating costs specified by the user.

Table A6-6 (Continued)
Control Case - Pipeline Corridor Input Data

No.	Corridor Name	Toll ($ C 1990/GJ)	Proposed Pipeline Year of Commercial Availability
38	North Central to East North Central	0.38	
39	West North Central to East North Central	0.61	
40	East North Central to Mid-Atlantic	0.78	1992
41	East North Central to Ontario	0.31	
42	East South Central to East North Central	0.25	
43	East South Central to South Atlantic	0.37	
44	East South Central to Mid-Atlantic	0.56	
45	Appalachia to South Atlantic	0.58	
46	Appalachia to Mid-Atlantic	0.58	
47	South Atlantic to Mid-Atlantic	0.20	
48	Mid-Atlantic to New England	0.37	
49	Pacific Northwest to California Border	0.12	1993
50	Pacific Northwest to Rockies	0.01	
51	California Border to S. California	0.37	1993
52	California Border to N. California[d]	0.11	
53	S. California to SOCALGAS Co.	0.19	
54	S. California to SDG&E	0.25	
55	S. California to EOR	0.12	
56	SOCALGAS Co. to EOR	0.50	
57	N. California to PG&E	0.19	
58	PG&E to EOR	0.47	
59	EOR to N. California	0.12	1993
60	EOR to S. California	0.12	1993
61	Offshore Atlantic to South Atlantic	0.87	1995
62	Offshore Atlantic to Mid-Atlantic	1.38	1995
63	Mexico to Gulf Coast	1.30	
64	LNG TO Gulf Coast	0.31	
65	LNG TO South Atlantic	0.31	
66	LNG TO New England	0.62	

[d] Transmission costs increase to $0.17 if flows exceed 0.40 Tcf/year.

No.	Corridor Name	Toll ($ C 1990/GJ)	Proposed Pipeline Year of Commercial Availability
67	Huntingdon to Pacific Northwest	0.26	
68	South Alberta[e] to California Border[f]	0.15	
69	South Alberta to Pacific Northwest	0.31	
70	South Alberta to West North Central	0.87	
71	South Alberta to Rockies (Altamont)	0.45	1993
72	Monchy to West North Central[g]	0.36	
73	Monchy to East North Central[h]	0.50	1992
74	Emerson[i] to East North Central	0.50	
75	New York Border[j] to Mid-Atlantic (Niagra)	0.38	
76	New York Border to Mid-Atlantic (Iroquois)	0.43	1992
77	Scotian Shelf to New England	1.98	2000
78	BC to BC Demand	0.31	
79	BC to Huntingdon	0.31	
80	BC to Alberta[k]	0.07	1988
81	Alberta to BC	0.03	
82	Alberta to Western Canada	0.28	
83	Alberta to Monchy	0.40	
84	Alberta to Saskatchewan	0.28	
85	Alberta to South Alberta	0.35	
86	Northern Canada to Alberta[l]	2.12	1996
87	Saskatchewan to Western Canada	0.28	
88	Saskatchewan to Ontario	0.85	
89	Saskatchewan to Emerson	0.28	
90	Ontario to Eastern Canada	0.00	
91	Ontario to New York Border	0.00	

[e] South Alberta includes Kingsgate, Reaganfield, Cardston and Aden export points
[f] Transmission costs increase to $0.22 if flows exceed 0.40 Tcf/year.
[g] Transmission costs increase to $0.53 if flows exceed 0.34 Tcf/year.
[h] Transmission costs increase to $0.74 if flows exceed 0.22 Tcf/year.
[i] Emerson includes Emerson, Sprague and Fort Frances export points
[j] NY Border includes Niagra, Cornwall, Phillipsburg, Highwater and Windsor export points
[k] Transmission costs increase to $0.14/Mcf if flows exceed 0.07 Tcf/year
[l] Maximum flows on this pipeline corridor have been specified at 0.70 Tcf/year.

Table A6-7
Control Case - Gas Distribution Charges

Average Canadian Distribution Charges by Region/Market

		Distribution Charge ($ C 1990/GJ)
Western Canada	Core	1.49
	Noncore	0.21
	Electric Gas/Oil	0.21
Eastern Canada	Core	2.93
	Noncore	0.71
	Electric Gas/Oil	0.71
Ontario	Core	2.24
	Noncore	0.41
	Electric Gas/Oil	0.41
British Columbia	Core	2.49
	Noncore	0.71
	Electric Gas/Oil	0.71

Average U.S. Distribution Charges by Region/Market

		Distribution Charge ($ C 1990/GJ)
Pacific Northwest	Core	3.45
	Noncore	0.62
	Electric Gas/Oil	0.43
California	Core	2.65
	Noncore	0.62
	Electric Gas/Oil	0.43
California - EOR	Noncore	0.00
West North Central and Mountain	Core	1.75
	Noncore	0.32
	Electric Gas/Oil	0.27
West South Central	Core	1.97
	Noncore	0.15
	Electric Gas/Oil	0.15
East North Central	Core	2.03
	Noncore	0.62
	Electric Gas/Oil	0.37
East South Central	Core	1.98
	Noncore	0.15
	Electric Gas/Oil	0.11
South Atlantic	Core	2.55
	Noncore	0.33
	Electric Gas/Oil	0.11
Mid-Atlantic	Core	3.31
	Noncore	0.62
	Electric Gas/Oil	0.22
New England	Core	3.05
	Noncore	0.62
	Electric Gas/Oil	0.19
Alaska	Core	0.06
	Electric Gas/Oil	0.06

Table A6-8
Total Demand for Canadian Natural Gas

(petajoules)

	End Use	Pipeline Fuel & Losses	Reprocessing Fuel	Electricity Generation[1]	Reprocessing Shrinkage	Domestic Demand	Net Exports	Total Demand	Gross Exports [2]	Imports [2]
1989	2073	180	14	140	240	2647	1386	4033	1432	46
1990	2003	182	23	102	241	2551	1487	4038	1515	28
1991	2094	191	24	52	256	2618	1668	4286	1693	25
1992	2138	200	26	54	276	2694	1920	4614	1941	21
1993	2185	204	26	58	280	2753	1917	4670	1953	36
1994	2227	208	27	63	285	2810	1956	4766	2007	51
1995	2267	212	28	69	291	2866	1995	4861	2061	66
1996	2303	215	28	62	296	2904	2035	4939	2115	80
1997	2322	218	29	70	300	2938	2074	5013	2169	95
1998	2337	219	29	77	301	2963	2072	5036	2186	114
1999	2372	220	29	72	303	2998	2070	5068	2203	133
2000	2413	222	30	85	307	3056	2068	5125	2220	152
2001	2421	223	30	100	308	3082	2066	5148	2237	171
2002	2434	224	30	119	310	3117	2064	5182	2254	190
2003	2449	226	31	88	314	3108	2130	5238	2337	207
2004	2461	229	31	102	320	3143	2196	5339	2420	224
2005	2473	231	32	111	326	3172	2262	5434	2503	241
2006	2481	233	32	106	330	3182	2328	5510	2586	258
2007	2486	235	33	122	336	3213	2395	5608	2669	274
2008	2485	232	33	132	333	3216	2339	5555	2610	271
2009	2489	229	32	114	328	3193	2284	5477	2551	267
2010	2484	226	32	122	325	3188	2228	5416	2492	264
Total	**51396**	**4757**	**629**	**2022**	**6608**	**65412**	**44944**	**110356**		

[1] Natural gas used to produce steam for bitumen projects included.
[2] 1989 actual, 1990 estimated actual.

Table A6-9

Productive Capacity from Established Reserves in WCSB

(petajoules)

	Productive Capacity from Producing Reserves						Productive Capacity from Non-producing Reserves				Total Canada Established	Remaining Marketable Reserves at 31 Dec	R/P Ratio Established
	Alberta	B.C.	Sask.	N.W.T.	Ontario	Canada	Alberta	B.C.	Sask.	Canada			
1990	4236	551	209	7	16	5019	81	8	2	91	5110	69559	14.61
1991	3982	535	217	25	16	4774	325	31	7	363	5137	64422	13.54
1992	3642	516	207	25	16	4406	649	62	15	725	5131	59291	12.56
1993	3307	500	180	25	14	4026	971	92	22	1085	5110	54180	11.60
1994	3000	481	152	22	13	3669	1210	115	26	1352	5021	49159	10.79
1995	2739	449	143	19	12	3362	1448	137	31	1616	4978	44181	9.87
1996	2474	415	130	18	11	3047	1519	144	32	1695	4742	39439	9.32
1997	2172	373	116	18	11	2690	1539	146	31	1715	4406	35033	8.95
1998	1938	324	102	15	10	2389	1547	146	30	1723	4113	30920	8.52
1999	1747	292	94	1	9	2143	1504	145	27	1676	3819	27102	8.10
2000	1567	259	87	1	9	1922	1399	141	24	1563	3485	23616	7.78
2001	1350	214	79	1	8	1652	1268	135	20	1424	3076	20541	7.68
2002	1225	178	72	0	8	1482	1121	128	17	1266	2749	17792	7.47
2003	1117	153	66	0	7	1343	951	119	14	1085	2428	15364	7.33
2004	988	131	60	0	7	1186	774	108	12	894	2080	13284	7.39
2005	838	112	49	0	7	1005	630	94	10	733	1738	11545	7.64
2006	735	94	40	0	7	876	503	78	9	590	1465	10080	7.88
2007	628	75	23	0	6	732	380	62	7	449	1181	8899	8.54
2008	538	52	14	0	6	611	293	49	6	348	959	7941	9.28
2009	486	43	9	0	6	544	230	37	5	272	815	7125	9.74
2010	433	38	5	0	6	482	191	30	5	226	708	6418	10.07

Table A6-10
Historical Data and Control Case Projection
Gas-Directed Exploratory Drilling and Marketable Gas Reserves Additions in WCSB

Historical Data			Control Case Projection		
	Gas-Directed Exploratory Drilling (millions of metres)	Marketable Gas Reserves Additions (EJ)		Gas-Directed Exploratory Drilling (millions of metres)	Marketable Gas Reserves Additions (EJ)
1970	1.24	2.34	1990	1.26	2.00
1971	1.11	5.76	1991	1.28	2.00
1972	1.56	0.34	1992	1.34	2.05
1973	1.69	4.22	1993	1.46	2.20
1974	1.49	1.78	1994	1.56	2.30
1975	1.34	1.87	1995	1.84	2.65
1976	1.87	5.22	1996	2.13	3.00
1977	2.21	6.41	1997	2.57	3.50
1978	2.63	8.23	1998	3.04	4.00
1979	2.78	5.00	1999	3.41	4.30
1980	3.50	3.22	2000	3.73	4.50
1981	2.67	7.36	2001	3.82	4.40
1982	1.58	3.45	2002	3.77	4.15
1983	1.14	1.36	2003	3.07	3.25
1984	1.43	1.52	2004	3.09	3.15
1985	1.50	1.92	2005	3.31	3.25
1986	1.12	1.27	2006	4.00	4.20
1987	1.45	0.00	2007	4.60	4.40
1988	1.44	2.30	2008	4.82	4.40
1989	1.96	7.26	2009	4.89	4.25
			2010	4.82	4.00

Table A6-11
Connection Rates for Reserves Additions
as a Function of Price/Demand Factor

(Percent per year)

	Price /Demand Factor		
Year	**1**	**2**	**3**
1	5	15	40
2	5	15	30
3	5	25	20
4	5	25	10
5	10	10	0
6	10	10	0
7	15	0	0
8	15	0	0
9	15	0	0
10	15	0	0
Total	**100**	**100**	**100**

Table A6-12
Historical Data - Natural Gas Supply and Demand - Conventional Areas

(Petajoules)	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
End Use [a]	**914**	**1018**	**1135**	**1156**	**1271**	**1265**	**1327**	**1428**	**1503**	**1592**
Pipeline fuel and losses	86	97	109	115	119	118	118	122	119	126
Reprocessing fuel	5	8	11	10	11	11	11	12	14	15
Total Own Use	**91**	**105**	**120**	**125**	**130**	**129**	**129**	**134**	**133**	**141**
Electricity Generation	99	100	148	200	173	195	139	132	106	104
Steam Production	0	0	0	0	0	0	0	0	0	0
Reprocessing Shrinkage	44	55	74	81	78	77	74	71	69	102
Domestic Demand	**1148**	**1278**	**1477**	**1562**	**1652**	**1666**	**1669**	**1765**	**1811**	**1939**
Exports	858	1003	1110	1130	1054	1019	1027	1077	949	1094
Imports	-11	-15	-17	-16	-14	-11	-4	0	0	0
Total Disposition [b]	**1995**	**2266**	**2570**	**2676**	**2692**	**2674**	**2692**	**2842**	**2760**	**3033**
Total Production	**2037**	**2260**	**2569**	**2741**	**2687**	**2728**	**2754**	**2872**	**2777**	**3007**
Productive Capacity [c]	**2280**	**2606**	**2822**	**2986**	**3148**	**3355**	**3520**	**3740**	**4015**	**4400**

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
End Use [a]	**1568**	**1561**	**1615**	**1629**	**1763**	**1875**	**1840**	**1818**	**2010**	**2073**
Pipeline fuel and losses	118	118	114	116	139	155	148	162	172	180
Reprocessing fuel	16	17	16	12	11	13	18	22	22	14
Total Own Use	**134**	**135**	**130**	**127**	**150**	**168**	**166**	**184**	**194**	**194**
Electricity Generation	84	69	61	75	68	56	60	55	67	137
Steam Production	0	0	0	0	0	0	1	2	2	2
Reprocessing Shrinkage	155	162	160	153	181	198	183	190	200	240
Domestic Demand	**1941**	**1926**	**1966**	**1985**	**2161**	**2297**	**2249**	**2249**	**2473**	**2646**
Exports	863	824	845	764	812	975	794	1058	1337	1432
Imports	0	0	0	0	0	0	-10	-4	-24	-46
Total Disposition [b]	**2804**	**2750**	**2811**	**2749**	**2973**	**3272**	**3033**	**3303**	**3786**	**4032**
Total Production	**2764**	**2739**	**2807**	**2664**	**2901**	**3162**	**2905**	**3135**	**3638**	**3843**
Productive Capacity [c]	**4840**	**5060**	**5335**	**5533**	**5335**	**5495**	**5269**	**5052**	**5022**	**5000**

Notes: The numbers on this table have been rounded.
[a] For end use demand by fuel and sector see Table A4-5.
[b] Total disposition differs from total production because of synthetic natural gas in disposition but not in production of natural gas, inventory changes, and statistical differences.
[c] Estimated from previous reports.

Table A6-13
Total Canada Productive Capacity

(petajoules)

	Productive Capacity from Established Reserves in WCSB					Productive Capacity From WSCB Additions	Total Productive Capacity From WSCB	Productive Capacity From Frontier Regions	Total Canada Productive Capacity	Total Canada Production	Total Canada Adjusted Productive Capacity
	Alberta	B.C.	Sask.	Other	Total						
1990	4317	559	211	23	5110	8	5118	0	5118	4034	5118
1991	4306	566	224	41	5137	25	5162	0	5162	4281	5170
1992	4290	578	221	41	5131	65	5196	0	5196	4614	5202
1993	4278	592	201	39	5110	130	5241	0	5241	4670	5256
1994	4211	596	179	35	5021	244	5265	0	5265	4766	5343
1995	4187	587	174	31	4978	413	5392	0	5392	4861	5436
1996	3993	559	161	29	4742	618	5360	0	5360	4939	5614
1997	3711	518	147	29	4406	868	5273	0	5273	5013	5657
1998	3485	471	132	25	4113	1148	5261	0	5261	5036	5657
1999	3251	437	121	10	3819	1457	5276	0	5276	5068	5700
2000	2965	399	111	10	3485	1768	5254	0	5254	5125	5779
2001	2618	349	99	9	3076	2070	5146	0	5146	5148	5825
2002	2346	306	89	8	2749	2370	5119	0	5119	5182	5839
2003	2068	272	81	7	2428	2643	5071	0	5071	5238	5775
2004	1763	239	72	7	2080	2917	4997	485	5482	5339	6269
2005	1467	205	59	7	1738	3178	4916	485	5401	5434	6349
2006	1239	172	48	7	1465	3410	4876	485	5361	5510	6386
2007	1008	137	30	6	1181	3602	4783	485	5268	5608	6363
2008	831	101	20	6	959	3763	4721	485	5206	5555	6290
2009	716	80	14	6	815	3864	4679	800	5479	5477	6506
2010	624	68	10	6	708	3950	4658	925	5583	5416	6560

Table A6-14
Projected R/P Ratios in WCSB

Year	I.M.R. [1] at Year-end (EJ)	WCSB [2] Production during year (EJ)	Cum. Prod. at Year-end (EJ)	Reserves Additions (EJ)	R.M.R. [3] at Year-end (EJ)	R/P [4]
1989	145.1	4.0	71.1	7.3	74.0	17.7
1990	147.1	4.0	75.1	2.0	71.9	18.3
1991	149.1	4.3	79.4	2.0	69.7	16.8
1992	151.1	4.6	84.0	2.1	67.1	15.1
1993	153.3	4.7	88.7	2.2	64.6	14.4
1994	155.6	4.8	93.5	2.3	62.2	13.6
1995	158.3	4.9	98.3	2.7	59.9	12.8
1996	161.3	4.9	103.3	3.0	58.0	12.1
1997	164.8	5.0	108.3	3.5	56.5	11.6
1998	168.8	5.0	113.3	4.0	55.5	11.2
1999	173.1	5.1	118.4	4.3	54.7	10.9
2000	177.6	5.1	123.5	4.5	54.1	10.7
2001	182.0	5.1	128.6	4.4	53.3	10.5
2002	186.1	5.2	133.8	4.2	52.3	10.3
2003	189.4	5.2	139.1	3.3	50.3	10.0
2004	192.5	4.9	143.9	3.2	48.6	10.4
2005	195.8	4.9	148.9	3.3	46.9	9.8
2006	200.0	5.0	153.9	4.2	46.1	9.3
2007	204.4	5.1	159.0	4.4	45.3	9.0
2008	208.8	5.1	164.1	4.4	44.7	8.9
2009	213.0	4.7	168.8	4.3	44.2	9.6
2010	217.0	4.5	173.3	4.0	43.8	9.9

[1] Initial Marketable Reserves
[2] Production from frontier regions excluded.
[3] Remaining Marketable Reserves
[4] Remaining Reserves:Production Ratio, i.e. previous year's R.M.R. divided by current year's production.

Appendix 7
Table A7-1
Historical Data
Initial and Remaining Established Reserves of Conventional Crude Oil - Total Canada

(Millions of Cubic Metres)

	Initial Reserves of Crude Oil			Remaining Reserves of Crude Oil		
	Light	Heavy	Total	Light	Heavy	Total
1967	-	-	2154.2	-	-	1610.5
1968	-	-	2258.0	-	-	1655.0
1969	-	-	2324.5	-	-	1659.2
1970	-	-	2348.7	-	-	1611.8
1971	-	-	2387.5	-	-	1573.4
1972	-	-	2406.8	-	-	1513.5
1973	-	-	2416.9	-	-	1420.6
1974	-	-	2413.5	-	-	1320.2
1975	1900.8	308.4	2209.2	901.2	128.1	1029.3
1976	1890.0	317.2	2207.2	826.2	127.9	954.1
1977	1920.7	325.1	2245.8	794.9	124.4	919.3
1978	1939.4	325.6	2265.0	752.4	114.1	866.5
1979	1935.2	352.3	2287.5	679.1	128.4	807.5
1980	1935.4	378.9	2314.3	615.4	144.3	759.7
1981	1980.4	355.7	2336.1	598.2	117.3	715.5
1982	2055.1	365.6	2420.7	616.5	119.2	735.7
1983	2085.5	385.7	2471.2	595.2	123.8	719.0
1984	2164.8	404.1	2568.9	612.9	127.7	740.6
1985	2217.2	419.0	2636.2	609.0	128.4	737.4
1986	2264.2	434.4	2698.6	600.7	130.1	730.8
1987	2288.1	456.1	2744.2	569.2	136.0	705.2
1988	2302.2	476.6	2778.8	526.2	140.0	666.2
1989	2400.1	487.5	2887.6	570.5	134.2	704.7

- data not available

Source: National Energy Board

Table A7-2
Conventional Oil Resources
Western Canada Sedimentary Basin

(Millions of Cubic Metres)

	Discovered Recoverable Resources [1]						Undiscovered Recoverable Resources [2]				Ultimate Potential Recovery [3]			
	Primary	Imp Oil Rec.	Initial Estab. Reserves	Future Imp. Oil Rec.	Total	Oil-in-place	Primary	Imp. Oil Rec.	Total	Oil-in-place	Primary	Imp Oil Rec.	Total	Oil-in-place
B.C.														
Light	60	30	90	10	100	251	13	7	20	55	73	46	119	306
Alberta														
Light	1378	604	1982	260	2242	6953	316	138	454	1593	1693	1003	2696	8546
Heavy	116	57	172	115	287	1422	72	35	107	770	188	207	395	2192
Saskatchewan														
Light	118	45	163	25	188	913	28	11	39	218	147	81	227	1131
Heavy*	176	139	315	205	520	2564	91	72	163	1155	267	416	683	3719
Manitoba														
Light	25	11	35	0	35	130	6	2	8	30	30	13	43	160
Total WCSB														
Light	1581	689	2270	295	2565	8246	363	158	521	1897	1944	1142	3086	10143
Heavy	292	196	488	320	808	3986	163	107	270	1925	455	623	1078	5911
Total	1872	885	2757	615	3372	12232	526	265	791	3822	2398	1765	4163	16054

* Estimated

[1] The total includes both initial primary and improved oil recovery reserves and future improved oil recovery for established pools. The total potential for established pools can be compared to the oil-in-place to obtain an estimate of the fraction of the in-place resource which is expected to be recovered in existing pools.

[2] Undiscovered resources includes future extensions to existing pools and new discoveries.

[3] The total ultimate potential recovery is the sum of discovered and undiscovered recoverable resources and can be compared to the aggregate oil in place to obtain an estimate of the fraction of the in-place resource which is expected to be recovered.

Table A7-3

Price Projections at Various Locations

	WTI at Cushing [a]	WTI at Chicago [a,b]	Light Alberta Edmonton[c]	Light / Bitumen Differential	Light Alberta Wellhead[d]	East Coast Offshore [e]	Beaufort[f]	Bitumen Alberta Wellhead[g]
				Control Case (1990 dollars)				
	$US/bbl	$CDN/m3				($CDN/m3)		
1990	20.00	151.03	143.03	62.72	135.03	143.03	39.03	80.31
1991	20.30	158.55	150.55	65.29	142.55	150.55	46.55	85.26
1992	20.61	162.60	154.60	66.91	146.60	154.60	50.60	87.69
1993	20.92	166.74	158.74	68.56	150.74	158.74	54.74	90.18
1994	21.24	168.92	160.92	69.66	152.92	160.92	56.92	91.26
1995	21.56	171.09	163.09	70.76	155.09	163.09	59.09	92.33
1996	21.88	173.25	165.25	71.86	157.25	165.25	61.25	93.39
1997	22.22	175.56	167.56	72.96	159.56	167.56	63.56	94.60
1998	22.55	177.78	169.78	74.06	161.78	169.78	65.78	95.72
1999	22.89	180.06	172.06	75.17	164.06	172.06	68.06	96.89
2000	23.24	182.42	174.42	76.27	166.42	174.42	70.42	98.15
2001	23.59	185.30	177.30	77.37	169.30	177.30	73.30	99.93
2002	23.95	188.26	180.26	78.47	172.26	180.26	76.26	101.79
2003	24.31	191.23	183.23	79.57	175.23	183.23	79.23	103.66
2004	24.68	194.28	186.28	80.67	178.28	186.28	82.28	105.61
2005	25.05	197.33	189.33	81.77	181.33	189.33	85.33	107.56
2006	25.43	200.47	192.47	82.87	184.47	192.47	88.47	109.60
2007	25.81	203.62	195.62	83.97	187.62	195.62	91.62	111.65
2008	26.20	206.84	198.84	85.07	190.84	198.84	94.84	113.77
2009	26.60	210.16	202.16	86.17	194.16	202.16	98.16	115.99
2010	27.00	213.48	205.48	87.27	197.48	205.48	101.48	118.21

[a] Foreign exchange rate $US per $1 CDN : 0.85 for 1990; .82 for 1991; .81 for 1992; and .80 after 1992.
[b] Canadian dollar price includes Cushing - Chicago oil pipeline toll of $US 0.40 per barrel.
[c] Pipeline toll from Chicago to Alberta are estimated at $C 8.00 per cubic metre.
[d] Pipeline/gathering costs in Alberta are estimated at $C 8.00 per cubic metre.
[e] Price difference between WTI at Chicago and wellhead price in East Coast offshore areas are estimated at $C 8.00 per cubic metre.
[f] Beaufort oil price obtained by subtracting $C 8.00 per cubic metre transportation cost from Chicago to Alberta, then deducting a pipieline toll of $C 104 per cubic metre for a 20,000 cubic metre per day pipeline to obtain a Beaufort wellhead price.
The $104 toll is based on only Amauligak oil moving through the pipelin, and includes shipping costs in Alberta to Edmonton.
[g] Bitumen price calculated by subtracting pipeline costs from Chicago to Alberta of $C 8.00 per cubic metre and a field bitumen/Edmonton par light differential.

Table A7-4

Historical Data and Projections

Oil-Directed Exploratory Drilling and Reserves Additions of Conventional Light and Heavy Crude Oil By Primary Recovery [a]

	Drilling (Millions of Metres)	Reserves Added [b] (Millions of Cubic Metres)	Additions Rate (Cubic Metres per Metre)
1965	1.2	79.2	66.4
1966	1.1	115.5	106.6
1967	1.1	88.5	79.3
1968	1.2	86.1	70.7
1969	1.3	3.1	2.4
1970	0.6	0.0	0.0
1971	0.6	33.8	52.2
1972	0.5	7.9	16.3
1973	0.6	3.4	6.0
1974	0.4	3.5	9.8
1975	0.3	11.6	38.1
1976	0.4	12.7	32.2
1977	0.6	21.2	35.7
1978	1.0	25.4	26.2
1979	1.3	21.2	15.9
1980	1.8	2.4	1.3
1981	1.5	37.7	25.8
1982	1.5	52.0	34.3
1983	1.6	46.8	28.6
1984	2.5	83.5	33.7
1985	3.0	43.4	14.3
1986	1.6	43.0	26.7
1987	1.9	26.4	13.6
1988	1.9	20.2	10.4
1989	1.2	16.2	13.2
1990	1.2	22.8	19.0
1991	1.2	22.1	18.4
1992	1.2	21.4	17.8
1993	1.2	20.7	17.2
1994	1.2	20.0	16.7
1995	1.2	19.1	16.2
2000	1.0	13.8	14.0
2005	0.9	11.6	12.3
2010	0.9	9.9	10.9

[a] Western Canada Sedimentary Basin

[b] Includes only reserve additions related to primary recovery.

Table A7-5
Incremental Direct Costs for Crude Oil [a]
Western Canada

Reserves Additions Increment [b] (Millions of Cubic Metres)	Control Case [c] ($C 1990 per Cubic Metre)
0 - 50	136
50 - 100	146
100 - 150	158
150 - 200	173
200 - 250	190
250 - 300	211
300 - 350	240
350 - 400	306

[a] Incremental direct costs for both light and heavy crude oil.
[b] Recoverable by primary mechanisms.
[c] Includes 10 percent royalty on marginal production.

Table A7-6
Frontier Crude Oil Supply Costs and Project Scheduling

Area & Field	Discovered Resources	Peak Production Rate	Supply Cost Before Taxes and Royalties in 1990 Dollars *			Real After Tax Rate of Return [h]	Year Construction Starts	Year of First Production
			Wellhead	Transportation	Cushing [1]			
	million m3	thousand m3/d	$C/m3	$C/m3	$US/bbl	percent		
East Coast Offshore								
Cohasset/Panuke [a]	5.6	2.6	110	8	15	31	1990	1992
Terra Nova [b]	50.0	13.9	140	8	19	17	1995	1998
Hibernia [c]	83.5	17.5	-	-	-	-	1990	1996
Beaufort/Mackenzie								
Amauligak [d]	53.2	12.3	80	112 [g]	25	19	2000	2004
Small Pools [e]	36.6	6.5	140	74 [g]	28	26	2009	2011
New Discoveries Required to Utilize Pipeline Capacity [f]	45.3	8.3	-	62 [g]	-	-	-	-

- data not available

* Exclusive of sunk costs.

(1) Foreign exchange rate $1.00 CDN = $US 0.80 .

[a] Project has been approved by regulatory agencies and production is expected to begin in the Spring of 1992.

[b] Production from a floating production system is economic at 1990 Control Case crude oil prices, but given the current project status, the start of construction is expected to be delayed to 1995, with production commencing in 1998.

[c] We have not included supply economics for Hibernia, as the project is presently under construction as a result of the recent legislative approval of the July 1988 Principles.

[d] Pipeline toll is based on Amauligak throughput only, although a 20-inch pipeline would have a capacity of 20,000 cubic metres per day or more.

[e] Pipeline toll is based on combined Amauligak and Small Pools throughput.

[f] Pipeline toll is based on peak Amauligak and Small Pools combined throughput being sustained over a 20-year period. This requires 135.1 million cubic metres of oil over the 20-year life of the pipeline, of which 45.3 million cubic metres represents undiscovered volumes.

[g] All pipeline tolls are based on the same pipeline capital and operating costs which were not varied with throughput. Tolls cited in footnotes [d], [e] and [f] vary with the amount of oil carried in the pipeline. The tolls include $C 8.00 per cubic metre to move oil from Edmonton to Chicago and $U.S. 0.40 to move it from Chicago to Cushing.

[h] Project rate of return on incremental capital (i.e., excluding sunk costs) using the control case price projections.

Table A7-7

Synthetic Crude Oil and Bitumen Supply Costs and Project Scheduling

Supply Cost Before Taxes and Royalties in 1990 Dollars [a]

Project	Project Productive Capacity	Plant Gate Cost of Feedstock	Cost of Upgrading	Plant Gate Cost of Synthetic Crude	Cushing [b], [c]	Real After Tax Rate of Return [h]	Year Construction Starts	Year of First Production
	thousand m3/d	$C/m3	$C/m3	$C/m3	$US/bbl	percent		
Bitumen Projects [d]	1 to 3	65 to 90	-	-	11 to 14	10 to 15	Variable	Variable
Upgrading Plants								
Husky Bi-Provincial [e]	7	87	96	183	25	1	1989	1993
Refinery Upgrader								
Project 1 [f]	3	87	82	169	23	12	2000	2004
Oilsands Mining Plants								
Project 1 [g]	12	-	-	-	27	8	2000	2005
Project 2 [g]	12	-	-	-	27	10	2004	2009

- data not available

[a] Exclusive of sunk costs.

[b] Foreign exchange rate $1.00 CDN = $US 0.80 .

[c] Add $C 16.00 per cubic metre to transport bitumen to Chicago; add $C 8.00 per cubic metre to transport synthetic or upgraded crude oil to Chicago and $U.: transportation between Chicago and Cushing.

[d] Projects commence production approximately 3 years after prices are equivalent to supply costs.

[e] Our analysis ignores certain benefits granted to this project by the federal and provincial governments.

[f] Comparison of the supply cost of refinery upgrading, at a ten percent real discount rate, shows the year 2006 as the date when the differential exceeds the cost of upgrading.

[g] Supply costs of producing synthetic crude oil do not cross our crude oil price projection until late in our projection period. The first project was slightly advanced from the crossover point.

[h] Project rate of return on incremental capital (i.e., excluding sunk costs) using the control case price projections.

Table A7-8

Conventional Light Crude Oil Reserves Additions and Productive Capacity
Western Canada Sedimentary Basin

	Additions (Millions of Cubic Metres)						Productive Capacity (Thousands of Cubic Metres Per Day)		
	Discovered Recoverable Resources				Undiscovered Recoverable Resources (Primary and Improved rec.)	Total Discovered and Undiscovered	Total Discovered Recoverable Resources	Undiscovered Recoverable Resources (Primary and Improved rec.)	Total Discovered and Undiscovered
	Infill*	Water Flood	Misc.	Total					
1990	1.0	3.0	1.0	5.0	15.1	20.1	0.5	1.7	2.3
1991	1.0	3.0	1.0	5.0	15.0	20.0	1.6	5.3	7.0
1992	1.0	3.5	1.0	5.5	14.9	20.4	2.8	9.1	11.9
1993	1.0	3.5	1.0	5.5	14.9	20.4	4.0	12.8	16.8
1994	1.0	3.5	1.0	5.5	14.8	20.3	5.2	16.6	21.8
1995	1.5	3.0	1.0	5.5	14.6	20.1	6.5	20.0	26.5
1996	1.5	2.5	1.5	5.5	14.3	19.8	7.6	22.9	30.5
1997	1.5	2.5	1.5	5.5	13.1	18.6	8.6	25.1	33.7
1998	2.0	2.0	2.0	6.0	12.3	18.3	9.5	26.8	36.3
1999	2.0	2.0	2.0	6.0	11.5	17.5	10.4	27.9	38.3
2000	2.5	1.5	3.0	7.0	10.9	17.9	11.2	28.6	39.8
2001	2.5	1.5	3.0	7.0	10.5	17.5	12.1	28.9	41.0
2002	2.5	1.5	3.0	7.0	10.1	17.1	12.9	29.0	41.9
2003	3.0	1.0	3.0	7.0	9.8	16.8	13.6	28.9	42.5
2004	3.0	1.0	3.0	7.0	9.4	16.4	14.2	28.7	42.9
2005	3.0	1.0	3.0	7.0	9.1	16.1	14.9	28.4	43.3
2006	3.0	1.0	3.0	7.0	8.8	15.8	15.5	28.2	43.7
2007	3.0	1.0	3.0	7.0	8.5	15.5	16.1	27.9	44.0
2008	3.0	1.0	2.0	6.0	8.3	14.3	16.6	27.7	44.3
2009	4.0	0.0	2.0	6.0	8.0	14.0	17.0	27.6	44.5
2010	4.0	0.0	2.0	6.0	7.8	13.8	17.3	27.4	44.8
Total	47.0	39.0	43.0	129.0	241.6	370.6			

* Note This category includes additions through infill drilling and technological improvements, such as horizontal drilling.

Table A7-9

Conventional Heavy Crude Oil Reserves Additions and Productive Capacity

Western Canada Sedimentary Basin

	Additions (Millions of Cubic Metres)						Productive Capacity (Thousands of Cubic Metres Per Day)		
	Discovered Recoverable Reserves				Undiscovered Recoverable Resources (Primary and Improved rec.)	Total Discovered and Undiscovered	Total Discovered Recoverable Resources	Undiscovered Recoverable Resources (Primary and Improved rec.)	Total Discovered and Undiscovered
	Infill*	Water Flood	Therm.	Total					
1990	0.5	2.0	0.0	2.5	14.5	17.0	0.2	0.9	1.1
1991	0.5	2.0	0.0	2.5	14.5	17.0	0.9	4.4	5.3
1992	0.5	2.5	0.0	3.0	14.6	17.6	1.6	8.5	10.1
1993	0.5	2.5	0.0	3.0	14.6	17.6	2.4	12.5	14.9
1994	0.5	2.0	0.0	2.5	14.6	17.1	3.2	16.5	19.7
1995	0.5	2.0	0.0	2.5	13.9	16.4	3.9	20.4	24.2
1996	0.5	2.0	0.0	2.5	13.3	15.8	4.4	23.4	27.8
1997	0.5	1.5	0.0	2.0	12.1	14.1	4.8	25.7	30.6
1998	0.5	1.5	0.0	2.0	11.4	13.4	5.1	27.3	32.4
1999	1.0	1.0	0.0	2.0	10.7	12.7	5.2	28.3	33.5
2000	1.0	1.0	0.0	2.0	10.2	12.2	5.4	28.8	34.1
2001	1.0	1.0	0.0	2.0	9.8	11.8	5.4	28.9	34.3
2002	1.5	1.0	0.0	2.5	9.5	12.0	5.5	28.8	34.3
2003	2.0	1.0	0.0	3.0	9.1	12.1	5.8	28.5	34.2
2004	2.0	1.0	0.0	3.0	8.8	11.8	6.1	28.0	34.1
2005	2.0	1.0	1.0	4.0	8.5	12.5	6.5	27.5	34.0
2006	3.0	0.0	1.5	4.5	8.3	12.8	7.2	27.0	34.2
2007	3.0	0.0	1.5	4.5	8.0	12.5	8.0	26.5	34.5
2008	3.0	0.0	2.0	5.0	7.8	12.8	8.7	26.0	34.8
2009	3.0	0.0	2.0	5.0	7.6	12.6	9.6	25.6	35.2
2010	3.0	0.0	2.0	5.0	7.4	12.4	10.3	25.3	35.6
Total	30.0	25.0	10.0	65.0	229.2	294.2			

* Note: This category includes additions through infill drilling and technological improvements, such as horizontal drilling.

Table A7-10
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pipeline and Region - Light Crude Oil

	Initial Established Reserves at 89/12/31	Cumulative Production to 89/12/31	Remaining Established Reserves at 89/12/31	Productive Capacity from Remaining Reserves at 89/12/31								
				1990	1991	1992	1993	1994	1995	2000	2005	2010
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Arctic Islands												
Bent Horn	1.000	0.180	0.820	130	130	130	130	130	130	130	127	0
Adjusted Total [a]				**130**	**130**	**130**	**130**	**130**	**130**	**130**	**127**	**0**
Northwest Territories												
Norman Wells	35.200	12.145	23.055	4900	4900	4900	4782	4347	3933	2385	1447	877
Adjusted Total [a]				**4900**	**4900**	**4900**	**4782**	**4347**	**3933**	**2385**	**1447**	**877**
British Columbia												
Blueberry Taylor Pipelines	19.435	14.774	4.661	1928	1605	1346	1137	965	823	393	175	70
Trans-Prairie Pipeline Ltd. Beaton River	29.813	26.318	3.495	1163	1015	877	761	663	581	306	180	98
Trans-Prairie Pipeline Ltd. Boundary Lake Taylo	34 916	27.941	6.975	1601	1472	1355	1247	1149	1059	707	468	317
Canadian Hunter Exploration Ltd. Pipeline	2.095	0.099	1.996	630	630	630	628	552	452	166	61	22
Truck and Tank Car	3.266	1.628	1.638	407	366	330	300	273	249	165	116	85
British Columbia Total	89.525	70.760	18.765	5729	5088	4538	4073	3602	3164	1737	1000	592
Adjusted Total [a]				**5729**	**5300**	**4762**	**4336**	**3889**	**3447**	**1903**	**1039**	**593**
Alberta												
Bow River Pipe Lines Ltd.	24.740	13.476	11.264	4163	3641	3093	2626	2243	1926	974	505	242
Cremona Pipeline System	38.298	32.714	5.584	2173	1870	1608	1390	1207	1052	483	215	120
Federated Pipe Lines Ltd.	350.145	281.617	68.528	16169	14618	13021	11442	10123	9017	5509	3698	2690
Gibson Petroleum Company Ltd.	16.488	12.520	3.968	2459	1932	1522	1201	951	754	218	0	0
Gulf Canada Pipeline	135.417	119.415	16.002	6483	5586	4775	4096	3496	2965	1312	593	179
Imperial Pipe Line Company, Limited-Ellerslie	61.500	58.248	3.252	1678	1246	975	790	655	553	277	148	9
Imperial Pipe Line Company, Limited-Excelsior	7.443	7.047	0.396	165	137	116	100	87	76	37	11	0
Imperial Pipe Line Company, Limited-Leduc	60.793	60.093	0.700	401	325	271	218	180	160	9	0	0
Imperial Pipe Line Company, Limited-Redwater	130.835	126 229	4.606	1886	1615	1388	1199	1039	904	450	190	0
Murphy Milk River Pipeline	7.241	4.468	2.773	1100	914	769	654	562	486	228	146	60
Norcen Energy Resources Ltd.	19.000	16.553	2.447	1000	992	867	724	605	505	205	0	0
Peace Pipe Line Ltd.	188.808	132.245	56.563	18405	16355	14346	12409	10644	9187	4794	2735	1720
Pembina Pipeline Company Ltd	355.683	247.735	107.948	23887	20344	16964	14380	12464	10961	6797	4865	3765
Rainbow Pipe Line Company Ltd.	276 385	208.715	67.670	21722	19208	16900	14491	12463	10780	5546	3114	1817
Rangeland Pipe Line Company Ltd.	93.346	68.507	24.839	7890	6787	5751	4933	4274	3741	2023	1272	768
Bonnie Glen Pipe Line	169.028	158.701	10.327	4549	3533	2808	2275	1873	1566	752	445	313
Trans-Prairie Pipelines Ltd.-Boundary Lake S.	5.604	3.751	1.853	475	430	389	353	320	291	183	118	74
Twining Pipeline Division	8.186	5.163	3.023	510	467	429	397	368	343	254	190	160
Valley Pipeline	25.486	22.395	3.091	402	386	371	357	344	330	272	224	184

Table A7-10 (Continued)
Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pipeline and Region - Light Crude Oil

	Initial Established Reserves at 89/12/31	Cumulative Production to 89/12/31	Remaining Established Reserves at 89/12/31	Productive Capacity from Remaining Reserves at 89/12/31								
	(Millions of Cubic Metres)			1990	1991	1992	1993	1994	1995	2000	2005	2010
				(Cubic Metres per Day)								
Alberta Cont'd.												
Truck and Tank Car	0.136	0.071	0.065	5	5	5	5	5	5	4	4	3
Undefined and Confidential	7.200	0.428	6.772	2500	2328	2004	1725	1485	1278	603	285	134
Alberta Total	**1981.762**	**1580.091**	**401.671**	**118022**	**102719**	**88372**	**75765**	**65388**	**56880**	**30930**	**18758**	**12238**
Adjusted Total [a]				**118022**	**106996**	**92734**	**80659**	**70607**	**61974**	**33878**	**19489**	**12258**
Saskatchewan												
Bow River Pipeline Ltd.-Light	18.252	13.496	4.756	1793	1578	1425	1184	1015	932	327	234	92
Producers Pipeline Company-Light	145.167	116.004	29.163	9220	8633	7680	6767	5976	5288	2898	1554	462
Saskatchewan Total	**163.419**	**129.500**	**33.919**	**11013**	**10211**	**9105**	**7951**	**6991**	**6220**	**3225**	**1788**	**554**
Adjusted Total [a]				**11013**	**10636**	**9554**	**8465**	**7549**	**6777**	**3532**	**1858**	**555**
Manitoba												
Trans-Prairie Pipelines Ltd.	35.182	27.121	8.061	1944	1811	1663	1530	1409	1301	840	602	370
Adjusted Total [a]				**1944**	**1886**	**1745**	**1629**	**1521**	**1418**	**920**	**625**	**371**
Ontario												
Ontario All	11.040	9.944	1.096	629	506	408	328	264	213	72	0	0
Adjusted Total [a]				**629**	**527**	**428**	**349**	**285**	**232**	**79**	**0**	**0**
Canada Total	**2317.128**	**1829.741**	**487.387**	**142367**	**125365**	**109116**	**94559**	**82131**	**71841**	**39319**	**23722**	**14631**
Reserves Life Index				**9.4**	**9.5**	**9.8**	**10.1**	**10.5**	**10.9**	**12.7**	**14.2**	**16.3**
Adjusted Productive Capacity [a]				**142367**	**130375**	**114253**	**100350**	**88328**	**77911**	**42827**	**24585**	**14654**
Adjusted Reserves Life Index				**9.4**	**9.2**	**9.3**	**9.5**	**9.6**	**9.8**	**10.5**	**11.3**	**12.0**

Note: [a] The Reserves Life Index of the unadjusted productive capacity forecast from established reserves in Canada increases from 9.4 in 1990 to 16.3 by 2010. We assume that infill drilling will accelerate production such that the Reserves Life Index for total Canadian production increases to only 12.0 by 2010. Regional productive capacity estimates have been adjusted accordingly.

Table A7-11
Productive Capacity of Frontier Oil

(Thousands of Cubic Metres Per Day)

	Cohasset / Panuke	Hibernia	Terra Nova	Unidentified Pools East Coast Offshore	Total East Coast	Bent Horn	Mackenzie / Beaufort	Total
1990	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0 1
1991	0.0	0.0	0.0	0.0	0.0	0.1	0 0	0.1
1992	2.6	0 0	0.0	0.0	2.6	0.1	0.0	2 7
1993	2.6	0.0	0.0	0.0	2.6	0.1	0.0	2.7
1994	2.6	0.0	0 0	0.0	2.6	0.1	0.0	2.7
1995	2.6	0.0	0.0	0.0	2 6	0.1	0.0	2.7
1996	2.5	1.8	0.0	0 0	4.3	0.1	0.0	4.4
1997	2.2	9.5	0.0	0.0	11.8	0.1	0.0	11.9
1998	0.0	17.5	7.0	0.0	24.4	0.1	0.0	24 6
1999	0.0	17.5	13.9	0.0	31.4	0.1	0.0	31.5
2000	0.0	17.5	13 9	0 0	31.4	0.1	0.0	31.5
2001	0.0	17.5	13.9	0.0	31.4	0.1	0.0	31.5
2002	0.0	17.5	13.9	4.7	36.1	0.1	0.0	36.2
2003	0.0	17.5	13.9	9.3	40.7	0.1	0.0	40.9
2004	0.0	17.5	13.9	9.3	40 7	0.1	8.5	49.4
2005	0.0	17.5	11.6	9.3	38.4	0.1	12.0	50.5
2006	0.0	17.5	9.6	11.0	38.1	0.1	12.3	50.4
2007	0.0	16.1	8.1	14.0	38.1	0.0	12.3	50.4
2008	0.0	13.0	6.7	18.3	38 1	0.0	12.3	50.4
2009	0.0	9.5	5.6	23 0	38.1	0.0	12.3	50.4
2010	0.0	7.3	4.7	26.1	38.1	0.0	12.3	50.4

Table A7-12

Productive Capacity from Reserves Additions in the WCSB by Province

(Thousands of Cubic Metres Per Day)

	Light					Heavy		
	B.C.	Alberta	Sask	Man	Total	Alberta	Sask	Total
1990	0.1	2.0	0.2	0.0	2.3	0.4	0.7	1.1
1991	0.3	6.1	0.5	0.1	7.0	2.1	3.2	5.3
1992	0.4	10.4	0.9	0.2	12.0	4.0	6.1	10.0
1993	0.6	14.8	1.3	0.2	17.0	5.9	9.0	14.9
1994	0.8	19.2	1.7	0.3	22.0	7.8	12.0	19.7
1995	1.0	23.2	2.0	0.4	26.6	9.5	14.7	24.2
1996	1.1	26.7	2.3	0.4	30.5	10.9	16.9	27.9
1997	1.3	29.5	2.6	0.4	33.7	12.0	18.6	30.6
1998	1.3	31.7	2.8	0.4	36.3	12.7	19.7	32.4
1999	1.4	33.4	2.9	0.5	38.2	13.2	20.4	33.5
2000	1.5	34.7	3.1	0.5	39.7	13.4	20.7	34.1
2001	1.5	35.8	3.2	0.5	40.9	13.4	20.9	34.3
2002	1.5	36.6	3.2	0.5	41.8	13.4	20.9	34.3
2003	1.6	37.1	3.3	0.5	42.5	13.4	20.8	34.2
2004	1.6	37.5	3.3	0.5	42.9	13.3	20.8	34.1
2005	1.6	37.8	3.4	0.5	43.3	13.3	20.7	34.0
2006	1.6	38.2	3.4	0.4	43.6	13.3	20.9	34.2
2007	1.6	38.5	3.4	0.4	44.0	13.4	21.1	34.5
2008	1.6	38.8	3.5	0.4	44.3	13.5	21.3	34.8
2009	1.6	38.9	3.5	0.4	44.5	13.6	21.6	35.2
2010	1.6	39.1	3.5	0.4	44.7	13.8	21.9	35.6

Table A7-13

Established Reserves of Conventional Crude Oil and Related Productive Capacity by Pipeline and Region - Heavy Crude Oil

	Initial Established Reserves at 89/12/31	Cumulative Production to 89/12/31	Remaining Established Reserves at 89/12/31	Productive Capacity from Remaining Reserves at 89/12/31								
				1990	1991	1992	1993	1994	1995	2000	2005	2010
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Alberta												
Bow River Pipe Lines Ltd.	97.893	67.026	30.867	13287	11608	9892	8306	6977	5845	2580	735	217
BP Exploration Canada Ltd	8.859	6.330	2.529	1271	1077	895	748	627	528	158	15	12
Husky & Murphy Manito Pipelines Lloyd.	41.849	30.089	11.760	4871	4319	3782	3252	2804	2425	929	393	0
Truck and Tank Car	18.135	9.102	9.033	5215	4136	3279	2599	2071	1645	423	121	53
Undefined and Confidential	5.639	0.000	5.639	1700	1601	1420	1260	1117	991	544	298	163
Alberta Total	172.375	112.547	59.828	26344	22741	19268	16165	13596	11434	4634	1562	445
Saskatchewan												
Husky SGS & Murphy Manito Pipelines. Lloyd.	68.882	48.232	20.650	7095	6680	5915	5217	4602	4042	1982	583	324
Bow River Pipe Lines Ltd.-Heavy	24.488	14.212	10.276	2499	2444	2237	2018	1824	1631	949	563	271
Bow River Pipe Lines Ltd.-Light Blend Heavy	6.290	5.342	0.948	407	363	327	296	270	247	73	0	0
South Saskatchewan Pipeline Company	102.395	85.513	16.882	5594	5168	4662	4155	3654	3213	1703	897	182
Producers Pipeline Company-S.E. Saskatchewa	113 031	87.534	25.497	6641	6078	5566	5098	4670	4280	2772	1791	1130
Saskatchewan Total	315.086	240.833	74.253	22236	20733	18707	16784	15020	13413	7479	3834	1907
Canada Total	487.461	353.380	134.081	48580	43474	37975	32949	28616	24847	12113	5396	2352
Reserves Life Index				7.6	7.3	7.2	7.2	7.1	7.1	6.6	6.4	6.0

Table A7-14

Productive Capacity of Crude Oil and Equivalent - Total Canada

(Thousands of Cubic Metres per Day)

	Light										Heavy						
	WCSB Light	Mackenzie/ Beaufort Light	East Coast Light	Bent Horn Light	Mining Syn-thetic	Upgraded Syn-thetic	Pentanes Plus [a]	Gross Diluent Req. [b]	Recycled Diluent [c]	Light and Equivalent Total	Convent-ional Heavy	Bitumen	Gross Diluent Req.	Blended Heavy Total	Upgrader Feed-stock [d]	Net Avail. Heavy	Total Crude & Equiv-alent
1989	152.7	0.0	0.0	0.1	32.6	0.0	18.9	-11.9	1.0	193.4	49.2	20.5	11.9	81.6	0.0	81.6	275.0
1990	144.7	0.0	0.0	0.1	32.2	8.0	18.6	-14.1	1.0	190.5	49.7	20.6	14.1	84.4	-8.0	76.4	266.9
1991	137.4	0.0	0.0	0.1	33.4	8.0	18.9	-14.1	1.0	184.7	48.8	20.9	14.1	83.8	-8.0	75.8	260.5
1992	126.2	0.0	2.6	0.1	33.9	8.0	20.9	-15.0	1.0	177.7	48.1	23.0	15.0	86.1	-8.0	78.1	255.8
1993	117.2	0.0	2.6	0.1	34.8	10.7	23.5	-15.6	1.8	175.1	47.9	24.6	15.6	88.1	-11.5	76.6	251.7
1994	110.1	0.0	2.6	0.1	36.6	14.4	23.9	-16.0	2.9	174.6	48.3	25.4	16.0	89.7	-16.3	73.4	248.0
1995	104.4	0.0	2.6	0.1	36.4	14.4	24.1	-16.5	2.9	168.4	49.1	26.5	16.5	92.1	-16.3	75.8	244.2
1996	99.4	0.0	4.3	0.1	36.4	14.4	24.3	-16.9	2.9	164.9	49.5	27.2	16.9	93.6	-16.3	77.3	242.2
1997	94.7	0.0	11.8	0.1	37.6	14.4	24.4	-17.0	2.9	168.9	49.5	27.5	17.0	94.0	-16.3	77.7	246.6
1998	90.4	0.0	24.4	0.1	37.6	14.4	24.3	-17.3	2.9	176.8	48.7	28.4	17.3	94.4	-16.3	78.1	254.9
1999	86.4	0.0	31.4	0.1	37.6	14.4	24.1	-18.6	2.9	178.3	47.5	31.9	18.6	98.0	-16.3	81.7	260.0
2000	82.6	0.0	31.4	0.1	37.6	14.4	24.2	-20.4	2.9	172.8	46.2	36.5	20.4	103.1	-16.3	86.8	259.6
2001	79.2	0.0	31.4	0.1	37.6	14.4	24.5	-21.3	2.9	168.8	44.7	39.1	21.3	105.1	-16.3	88.8	257.6
2002	76.0	0.0	36.1	0.1	37.6	14.4	26.4	-23.2	2.9	170.3	43.3	44.0	23.2	110.5	-16.3	94.2	264.5
2003	73.0	0.0	40.7	0.1	37.6	14.4	27.4	-24.7	2.9	171.4	42.0	47.9	24.7	114.6	-16.3	98.3	269.7
2004	70.3	8.5	40.7	0.1	37.6	17.0	26.8	-26.8	4.0	178.2	40.5	53.3	26.8	120.6	-20.0	100.6	278.8
2005	67.9	12.0	38.4	0.1	40.0	20.5	27.4	-27.8	5.5	184.0	39.4	55.9	27.8	123.1	-25.0	98.1	282.1
2006	65.8	12.3	38.1	0.0	47.1	20.5	28.1	-28.1	5.5	189.3	39.0	56.6	28.1	123.7	-25.0	98.7	288.0
2007	63.9	12.3	38.1	0.0	49.7	20.5	27.8	-28.3	5.5	189.5	38.5	57.3	28.3	124.1	-25.0	99.1	288.6
2008	62.2	12.3	38.1	0.0	49.7	20.5	27.5	-30.3	5.5	185.5	38.0	62.3	30.3	130.6	-25.0	105.6	291.1
2009	60.7	12.3	38.1	0.0	52.1	20.5	27.2	-32.5	5.5	183.9	38.0	67.5	32.5	138.0	-25.0	113.0	296.9
2010	59.5	12.3	38.1	0.0	59.2	20.5	27.7	-34.8	5.5	188.0	38.0	72.8	34.8	145.6	-25.0	120.6	308.6

Notes [a] IncludesMackenzie Delta supply (2002), East Coast supply (2010) and condensate (refer to the following chapter on Natural Gas Liquids for an explanation of projection method).

[b] Diluent required for heavy crude and bitumen blending is removed from the light crude oil supply and added to the heavy crude oil supply. Diluent requirements in excess of the supply of pentanes plus are assumed to be met by light crude.

[c] Includes diluent currently being recycled (approximately 1 thousand cubic metres per day) and future volumes to be recycled from upgraders.

[d] Blended heavy crude used as upgrader feedstock is included in the light crude supply as upgraded synthetic crude and recycled diluent.

Table A7-15

Refinery Feedstock Requirements and Sources - Canada and Regions

Canada

Feedstock Requirements [a] (Thousands of Cubic Metres)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Domestic Product Demand [b]	86400	87095	85876	86429	87249	88081	88317	91975	97368	105255
Deduct Product Imports	-10248	-7426	-9900	-9900	-9900	-9900	-9900	-11000	-13600	-16800
Add Product Exports	12381	11603	12550	12550	12550	12550	12550	12550	12550	12550
Net Regional Transfers -In/+Out	0	0	0	0	0	0	0	0	0	0
Product Inventory +Build/-Draw	-32	-1422	0	0	0	0	0	0	0	0
Add Own Consumption	5683	5530	5494	5531	5582	5636	5653	5815	5988	6287
Total	**94184**	**95380**	**94020**	**94610**	**95481**	**96367**	**96620**	**99341**	**102306**	**107293**
Per Day	**258.0**	**261.3**	**257.6**	**258.5**	**261.6**	**264.0**	**264.7**	**271.4**	**280.3**	**294.0**
Feedstock Sources (Thousands of Cubic Metres Per Day)										
Domestic: Heavy	19.4	18.0	17.2	16.0	16.4	16.4	17.7	19.8	22.0	25.1
Light	145.8	150.2	146.9	142.6	144.0	145.4	145.5	121.3	125.5	129.9
Imports	77.3	81.9	80.9	87.4	88.7	89.7	89.0	117.8	120.3	126.4
Inventory Change	0.6	-1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	243.1	249.1	245.1	246.0	249.1	251.5	252.2	258.9	267.8	281.5
Partially Processed Oil and Other Material	11.8	9.8	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Gas Plant Butanes/MTBE	3.1	2.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Total	**258.0**	**261.3**	**257.6**	**258.5**	**261.6**	**264.0**	**264.7**	**271.4**	**280.3**	**294.0**

Notes: [a] 1989 based on actual data from Statistics Canada Catalogue 45-004.

[b] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Atlantic

Feedstock Requirements [a] (Thousands of Cubic Metres)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Domestic Product Demand [b]	12193	11704	11511	11490	11689	11799	11380	11457	11892	12548
Deduct Product Imports	-3186	-2624	-3000	-3000	-3000	-3000	-3000	-3000	-3000	-3000
Add Product Exports	6478	6467	7000	7000	7000	7000	7000	7000	7000	7000
Net Regional Transfers -In/+Out	167	510	500	500	500	500	500	500	500	500
Product Inventory +Build/-Draw	258	299	0	0	0	0	0	0	0	0
Add Own Consumption	952	970	950	949	960	967	942	947	972	1011
Total	**16862**	**17326**	**16961**	**16939**	**17150**	**17266**	**16822**	**16904**	**17364**	**18059**
Per Day	**46.2**	**47.5**	**46.5**	**46.3**	**47.0**	**47.3**	**46.1**	**46.2**	**47.6**	**49.5**
Feedstock Sources (Thousands of Cubic Metres Per Day)										
Domestic: Heavy	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imports	46.5	47.2	46.5	46.3	47.0	47.3	46.1	46.2	47.6	49.5
Inventory Change	-0.3	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	46.2	47.5	46.5	46.3	47.0	47.3	46.1	46.2	47.6	49.5
Partially Processed Oil and Other Material	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas Plant Butanes/MTBE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**46.2**	**47.5**	**46.5**	**46.3**	**47.0**	**47.3**	**46.1**	**46.2**	**47.6**	**49.5**

Notes: [a] 1989 based on actual data from Statistics Canada Catalogue 45-004.
[b] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A7-15 (Continued)

Refinery Feedstock Requirements and Sources - Canada and Regions

Quebec

Feedstock Requirements [a] (Thousands of Cubic Metres)	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Domestic Product Demand [b]	19350	18999	18728	18861	19014	19255	19422	20265	21310	22946
Deduct Product Imports	-5071	-2945	-5000	-5000	-5000	-5000	-5000	-5700	-6500	-7200
Add Product Exports	903	575	750	750	750	750	750	750	750	750
Net Regional Transfers -In/+Out	238	204	-500	-500	-500	-500	-500	-500	-500	-500
Product Inventory +Build/-Draw	-952	-1754	0	0	0	0	0	0	0	0
Add Own Consumption	968	962	940	949	959	975	987	996	1013	1075
Total	**15436**	**16041**	**14918**	**15060**	**15223**	**15481**	**15659**	**15811**	**16073**	**17071**
Per Day	**42.3**	**43.9**	**40.9**	**41.1**	**41.7**	**42.4**	**42.9**	**43.2**	**44.0**	**46.8**
Feedstock Sources (Thousands of Cubic Metres Per Day)										
Domestic: Heavy	4.3	4.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light	9.3	7.9	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imports	26.5	32.2	34.5	41.1	41.7	42.4	42.9	43.2	44.0	46.8
Inventory Change	1.1	-0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	41.1	43.2	40.9	41.1	41.7	42.4	42.9	43.2	44.0	46.8
Partially Processed Oil and Other Material	1.2	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas Plant Butanes/MTBE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**42.3**	**43.9**	**40.9**	**41.1**	**41.7**	**42.4**	**42.9**	**43.2**	**44.0**	**46.8**

Notes: [a] 1989 based on actual data from Statistics Canada Catalogue 45-004.

[b] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Ontario

Feedstock Requirements [a] (Thousands of Cubic Metres)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Domestic Product Demand [b]	28265	28708	28480	28772	29004	29269	29549	31216	33924	38277
Deduct Product Imports	-1260	-1335	-1300	-1300	-1300	-1300	-1300	-1700	-3500	-6000
Add Product Exports	3293	2827	3000	3000	3000	3000	3000	3000	3000	3000
Net Regional Transfers -In/+Out	-1494	-1596	-1500	-1500	-1500	-1500	-1500	-1500	-1500	-1500
Product Inventory +Build/-Draw	-772	-340	0	0	0	0	0	0	0	0
Add Own Consumption	2120	1965	1994	2014	2030	2049	2068	2156	2219	2348
Total	**30152**	**30229**	**30674**	**30986**	**31235**	**31518**	**31817**	**33172**	**34144**	**36125**
Per Day	**82.6**	**82.8**	**84.0**	**84.7**	**85.6**	**86.4**	**87.2**	**90.6**	**93.5**	**99.0**
Feedstock Sources (Thousands of Cubic Metres Per Day)										
Domestic: Heavy	9.7	8.4	10.4	10.5	10.7	10.7	11.6	12.9	14.3	16.2
Light	64.5	68.5	69.9	70.5	71.2	71.9	71.9	45.6	46.8	48.9
Imports	4.3	2.5	0.0	0.0	0.0	0.0	0.0	28.4	28.7	30.2
Inventory Change	-0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	78.3	79.6	80.3	81.0	81.9	82.7	83.5	86.9	89.8	95.3
Partially Processed Oil and Other Material	3.9	2.9	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Gas Plant Butanes/MTBE	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**82.6**	**82.8**	**84.0**	**84.7**	**85.6**	**86.4**	**87.2**	**90.6**	**93.5**	**99.0**

Notes: [a] 1989 based on actual data from Statistics Canada Catalogue 45-004.
[b] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A7-15 (Continued)

Refinery Feedstock Requirements and Sources - Canada and Regions

Prairies & NWT

Feedstock Requirements [a] (Thousands of Cubic Metres)	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Domestic Product Demand [b]	16843	17512	17299	17276	17376	17458	17552	17973	18519	19137
Deduct Product Imports	-79	-12	0	0	0	0	0	0	0	0
Add Product Exports	902	847	1000	1000	1000	1000	1000	1000	1000	1000
Net Regional Transfers -In/+Out	4402	3425	4500	4500	4500	4500	4500	4500	4500	4500
Product Inventory +Build/-Draw	-99	175	0	0	0	0	0	0	0	0
Add Own Consumption	1166	1155	1200	1199	1204	1208	1213	1235	1264	1297
Total	**23135**	**23102**	**23999**	**23975**	**24080**	**24166**	**24266**	**24708**	**25283**	**25933**
Per Day	**63.4**	**63.3**	**65.7**	**65.5**	**66.0**	**66.2**	**66.5**	**67.5**	**69.3**	**71.1**
Feedstock Sources (Thousands of Cubic Metres Per Day)										
Domestic: Heavy	4.8	4.9	4.8	4.9	5.1	5.1	5.4	6.1	6.8	7.9
Light	54.8	56 0	57.9	57 6	57.9	58.1	58.1	58 4	59 5	60.2
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	0.2	-0.2	0 0	0 0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	59.8	60.7	62 7	62.5	63.0	63.2	63 5	64.5	66.3	68.1
Partially Processed Oil and Other Material	0.9	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Gas Plant Butanes/MTBE	2.7	2.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Total	**63.4**	**63.3**	**65.7**	**65.5**	**66.0**	**66.2**	**66.5**	**67.5**	**69.3**	**71.1**

Notes [a] 1989 based on actual data from Statistics Canada Catalogue 45-004.

[b] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

British Columbia & Yukon

Feedstock Requirements [a] (Thousands of Cubic Metres)	**1989**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Domestic Product Demand [b]	9750	10172	9857	10029	10165	10300	10413	11065	11723	12349
Deduct Product Imports	-652	-510	-600	-600	-600	-600	-600	-600	-600	-600
Add Product Exports	805	887	800	800	800	800	800	800	800	800
Net Regional Transfers -In/+Out	-3313	-2543	-3000	-3000	-3000	-3000	-3000	-3000	-3000	-3000
Product Inventory +Build/-Draw	1532	198	0	0	0	0	0	0	0	0
Add Own Consumption	477	478	411	421	429	437	443	481	519	556
Total	**8599**	**8682**	**7468**	**7649**	**7794**	**7937**	**8056**	**8746**	**9442**	**10104**
Per Day	**23.6**	**23:8**	**20.5**	**20.9**	**21.4**	**21.7**	**22.1**	**23.9**	**25.9**	**27.7**
Feedstock Sources (Thousands of Cubic Metres Per Day)										
Domestic: Heavy	0.6	0.3	0.6	0.6	0.6	0.6	0.7	0.8	0.9	1.0
Light	17.3	17.8	14.1	14.5	15.0	15.3	15.6	17.3	19.2	20.9
Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inventory Change	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	17.7	18.1	14.7	15.1	15.6	15.9	16.3	18.1	20.1	21.9
Partially Processed Oil and Other Material	5.8	5.6	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
Gas Plant Butanes/MTBE	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**23.6**	**23.8**	**20.5**	**20.9**	**21.4**	**21.7**	**22.1**	**23.9**	**25.9**	**27.7**

Notes: [a] 1989 based on actual data from Statistics Canada Catalogue 45-004.
[b] Domestic product demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A7-16
Supply and Disposition of Domestic Crude Oil and Equivalent - Canada

(Thousands of Cubic Metres Per Day)

	Control Case									
	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Heavy Crude Oil										
Domestic Supply										
Actual Production and Productive Capacity	78.1	76.4	75.8	78.1	76.6	73.4	75.8	86.8	98.1	120.6
Inventory -Build/+Draw	-3.0	0.5								
Total Domestic Supply	**75.1**	**76.9**	**75.8**	**78.1**	**76.6**	**73.4**	**75.8**	**86.8**	**98.1**	**120.6**
Disposition of Domestic Supply										
Atlantic	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Quebec	4.3	4.0	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ontario	9.7	8.4	10.4	10.5	10.7	10.7	11.6	12.9	14.3	16.2
Prairies & NWT	4.8	4.9	4.8	4.9	5.1	5.1	5.4	6.1	6.8	7.9
British Columbia & Yukon	0.6	0.3	0.6	0.6	0.6	0.6	0.7	0.8	0.9	1.0
Total Canada	19.4	18.0	17.2	16.0	16.4	16.4	17.7	19.8	22.0	25.1
Exports	**55.7**	**58.9**	**58.6**	**62.1**	**60.2**	**57.0**	**58.1**	**67.0**	**76.1**	**95.5**
Light Crude Oil and Equivalent										
Domestic Supply										
Actual Production and Productive Capacity										
East Coast	0.1	0.1	0.1	2.7	2.7	2.7	2.7	31.5	38.5	38.1
Beaufort Sea									12.0	12.3
W. Canada	187.8	190.4	184.6	175.0	172.4	171.9	165.7	141.3	133.5	137.6
Inventory -Build/+Draw	5.0	4.2								
Total Domestic Supply	**192.9**	**194.7**	**184.7**	**177.7**	**175.1**	**174.6**	**168.4**	**172.8**	**184.0**	**188.0**
Disposition of Domestic Supply										
Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Quebec	9.3	7.9	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ontario	64.5	68.5	69.9	70.5	71.2	71.9	71.9	45.6	46.8	48.9
Prairies & NWT	54.8	56.0	57.9	57.6	57.9	58.1	58.1	58.4	59.5	60.2
British Columbia & Yukon	17.3	17.8	14.1	14.5	15.0	15.3	15.6	17.3	19.2	20.9
Total Canada	145.8	150.2	146.9	142.6	144.0	145.4	145.5	121.3	125.5	129.9
Exports	**47.1**	**44.5**	**37.8**	**35.1**	**31.1**	**29.2**	**22.9**	**51.5**	**58.5**	**58.1**

Appendix 8

Table A8-1

Historical Data - Natural Gas Liquids Production - Canada

(Thousands of Cubic Metres per Day)

	Ethane	Propane			Butanes			Pentanes Plus
	Gas Plants[a]	Gas Plants[a]	Refineries[b]	Total	Gas Plants[a]	Refineries[b]	Total	Gas Plants[a,c]
1970	0.4	9.8	2.3	12.1	6.4	1.2	7.6	19.4
1971	1.0	12.2	2.3	14.5	8.0	0.7	8.7	21.0
1972	0.9	14.5	2.3	16.8	9.6	0.4	10.0	26.8
1973	1.1	16.4	2.6	19.0	10.8	0.7	11.5	27.6
1974	1.7	16.3	2.6	18.9	11.0	0.9	11.9	26.4
1975	1.7	17.0	3.1	20.1	11.2	1.0	12.2	24.8
1976	1.5	16.2	3.5	19.7	10.8	1.0	11.8	21.8
1977	1.8	16.3	3.7	20.0	10.9	1.4	12.3	21.5
1978	4.8	15.5	3.6	19.1	10.1	1.5	11.6	19.4
1979	10.8	16.9	3.5	20.4	10.9	1.9	12.8	19.3
1980	13.1	16.2	3.8	20.0	10.2	2.3	12.5	17.4
1981	13.8	15.8	3.7	19.5	9.8	2.9	12.7	16.7
1982	12.7	15.8	3.2	19.0	9.8	2.5	12.3	16.4
1983	13.9	15.3	3.5	18.8	9.5	2.6	12.1	15.4
1984	16.6	16.5	3.6	20.1	9.8	2.4	12.2	16.1
1985	18.1	16.9	3.1	20.0	9.7	2.2	11.9	17.2
1986	20.9	17.4	3.6	21.0	9.7	2.3	12.0	17.4
1987	25.4	19.3	4.6	23.9	10.7	2.1	12.8	18.6
1988	29.5	20.7	4.2	24.9	11.4	2.5	13.9	19.1
1989	28.1	21.0	4.5	25.5	11.2	2.0	13.2	19.5

Notes:[a] Provincial NGL gas plant production figures have been adjusted upwards to account for each gas liquid component of mixes injected in miscible flood or other injection schemes. Production of specification ethane did not begin until 1974.

[b] Refinery production is net of own use. Source: 1970 - 1974 Statistics Canada, 1975 - 1986 NEB 145 summaries,and 1987 - 1989 Statistics Canada.

[c] Includes field condensate production.

Table A8-2
Natural Gas Liquids Production - Canada

(Thousands of Cubic Metres per Day)

Control Case

	Ethane	Propane			Butanes			Pentanes Plus
	Gas Plants	Gas Plants	Refineries	Total	Gas Plants	Refineries	Total	Gas Plants[a]
1989	28.1	21.0	4.5	25.5	11.2	2.0	13.2	19.5
1990	29.0	21.5	4.5	26.0	11.1	2.0	13.1	19.0
1991	30.0	22.1	4.6	26.7	11.2	2.1	13.3	19.4
1992	32.9	24.3	4.6	28.9	12.3	2.1	14.4	21.3
1993	34.1	25.4	4.6	30.0	13.3	2.1	15.4	23.8
1994	34.8	25.6	4.7	30.3	13.5	2.1	15.6	24.0
1995	35.5	25.9	4.7	30.6	13.7	2.1	15.8	24.2
1996	36.3	26.1	4.7	30.8	14.0	2.1	16.1	24.4
1997	37.0	26.2	4.7	30.9	14.1	2.1	16.2	24.5
1998	37.2	26.1	4.7	30.8	14.0	2.2	16.2	24.4
1999	37.5	26.0	4.8	30.8	13.9	2.2	16.1	24.2
2000	38.0	26.0	4.8	30.8	13.9	2.2	16.1	24.3
2001	38.3	26.2	4.8	31.0	14.1	2.2	16.3	24.6
2002	38.5	26.4	4.9	31.3	14.3	2.2	16.5	26.5
2003	39.4	26.9	4.9	31.8	14.7	2.2	16.9	27.5
2004	40.2	27.5	4.9	32.4	15.2	2.2	17.4	26.9
2005	41.2	28.2	5.0	33.2	15.7	2.2	17.9	27.6
2006	42.1	28.7	5.0	33.7	16.1	2.2	18.3	28.3
2007	43.0	29.3	5.1	34.4	16.5	2.3	18.8	28.0
2008	42.8	29.1	5.1	34.2	16.3	2.3	18.6	27.7
2009	42.7	28.8	5.1	33.9	16.2	2.3	18.5	27.4
2010	41.5	28.4	5.1	33.5	16.0	2.3	18.3	27.9

Note: [a] Includes field condensate

Table A8-3
Ethane Production from Selected Gas Plants

(Cubic Metres per Day)

Control Case

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Field Plants										
Bonnie Glen (Esso)	731	680	553	454	380	323	278	151	96	140
Brazeau (Chevron)*	238	264	244	217	191	167	146	103	109	122
Caroline (Shell)	0	0	0	275	2200	2200	2200	2200	1903	899
Elmworth (Canadian Hunter)*	247	270	295	269	249	224	203	136	82	41
Elmworth (Esso)*	820	672	537	438	363	305	260	124	55	27
Judy Creek (Esso)*	3574	3373	4314	4191	3990	4019	4332	4177	3049	2255
Jumping Pound (Shell)	421	411	403	395	387	379	372	244	149	87
Kaybob South (Chevron)*	735	713	691	618	550	668	515	139	22	8
Nipisi (Amoco)*	88	83	75	68	61	56	50	30	18	11
Peco (Conoco)*	134	0	0	0	0	0	0	0	0	0
Turner Valley (Pembina)	171	151	137	124	112	102	92	56	34	21
Waterton (Shell)	274	266	257	250	240	235	230	169	126	87
Wembley (Amoco)*	663	637	600	585	570	560	550	500	450	400
Subtotal	8096	7520	8106	7884	9293	9238	9228	8029	6093	4098
Straddle Plants										
Cochrane (A.N.G.C.)	6169	6300	6390	6490	6420	6360	6300	6150	6650	8530
Ellerslie (Amoco)	1431	1400	1400	1400	1400	1400	1400	1400	1400	1400
Empress (3 plants)	10203	10500	11210	12150	12425	12800	13065	13820	14650	14390
Fort Saskatchewan (Midwest)*	116	116	116	116	116	116	116	116	116	116
Subtotal	17919	18316	19116	20156	20361	20676	20881	21486	22816	24436
Total[a]	26015	25836	27222	28040	29654	29914	30109	29515	28909	28534

Notes: [*] All or part of the production is entrained in an NGL mix.
[a] These plants accounted for 94 percent of gas plant ethane production in 1989.

Table A8-4
Propane Production from Selected Gas Plants

(Cubic Metres per Day)

Control Case

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Field Plants										
Bonnie Glen (Esso, 2Plants)	886	800	744	628	538	466	408	233	126	209
Brazeau (Chevron)*	109	122	114	101	90	78	68	55	64	73
Brazeau (Petro-Canada,2 Plants)*	110	103	96	90	84	78	73	46	33	20
Caroline (Shell)	0	0	0	131	1050	1050	1050	1050	909	429
Carson Creek (Mobil)	206	230	222	193	163	136	112	41	9	1
Carstairs (Home)	210	179	155	134	113	98	79	49	32	20
Elmworth (Canadian Hunter)*	275	255	230	210	195	175	161	115	65	35
Elmworth (Esso)*	312	262	210	172	142	119	102	49	21	11
Ferrier (Amerada)	290	250	216	186	160	137	118	47	30	20
Harmattan-Elkton (Mobil)	386	369	359	340	322	305	289	192	98	49
Homeglen-Rimbey (Gulf)	1055	991	907	813	720	643	580	374	238	126
Judy Creek (Esso)*	1545	1452	1433	1392	1325	1335	1439	1387	1012	749
Jumping Pound (Shell)	155	154	151	148	145	142	140	91	56	33
Kaybob (Petro-Canada)*	102	103	104	100	90	83	76	50	34	18
Kaybob South (Chevron)*	402	388	374	343	314	334	260	74	12	4
Kaybob South (Amoco, 2 Plants)*	448	415	387	359	332	342	286	121	56	29
Mitsue (Chevron)*	402	413	422	414	364	318	278	137	66	31
Nevis (Gulf)	217	225	224	223	218	208	200	159	108	77
Nipisi (Amoco)*	181	168	151	136	122	110	99	58	34	20
Peco (Conoco)*	93	47	48	49	49	48	47	37	22	12
Ricinus (Amoco)	394	382	371	355	337	325	312	259	201	116
Strachan(Gulf)	250	234	219	206	192	181	170	119	83	57
Turner Valley (Pembina)	119	107	97	88	80	72	65	40	24	15
Waterton (Shell)	268	260	241	224	201	194	188	127	84	53
Wembley (Amoco)*	380	387	355	345	340	335	330	300	270	240
Subtotal	8795	8296	7830	7380	7686	7312	6930	5210	3687	2447
Straddle Plants										
Cochrane (A.N.G.C.)*	1839	1880	1900	1935	1915	1895	1880	1835	1985	2542
Ellerslie (Amoco)*	739	735	735	735	735	735	735	735	735	735
Empress (3 plants)*	4502	4635	4950	5360	5480	5650	5765	6100	6460	6350
Fort Saskatchewan (Midwest)*	47	47	47	47	47	47	47	47	47	47
Subtotal	7127	7297	7632	8077	8177	8327	8427	8717	9227	9674
Total[a]	15922	15593	15462	15457	15863	15639	15357	13927	12914	12121

Note:[*] All or part of the production is entrained in an NGL mix.
[a] These plants accounted for 77 percent of gas plant propane production in 1989.

Table A8-5

Butanes Production from Selected Gas Plants

(Cubic Metres per Day)

Control Case

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Field Plants										
Bonnie Glen (Esso, 2Plants)	499	460	436	368	315	274	241	149	78	99
Brazeau (Chevron)*	65	74	70	62	55	48	41	30	32	35
Brazeau (Petro-Canada,2 Plants)*	100	94	88	81	75	41	68	43	32	19
Caroline (Shell)	0	0	0	135	1075	1075	1075	1075	933	441
Carson Creek (Mobil)	131	147	142	124	105	87	72	26	6	1
Carstairs (Home)	179	154	134	118	102	89	74	47	31	20
Elmworth (Canadian Hunter)*	136	121	107	95	88	78	72	55	35	20
Elmworth (Esso)*	128	110	103	84	70	59	50	24	11	5
Ferrier (Amerada)	143	124	108	94	82	71	62	29	20	13
Harmattan-Elkton (Mobil)	286	270	264	250	236	223	211	141	72	36
Homeglen-Rimbey (Gulf)	595	556	507	454	404	363	330	223	147	78
Judy Creek (Esso)*	916	872	760	739	704	709	764	737	538	398
Jumping Pound (Shell)	135	134	132	129	127	124	122	79	48	29
Kaybob (Petro-Canada)*	58	61	62	59	54	51	47	33	24	13
Kaybob South (Chevron)*	313	292	271	243	217	239	186	53	8	3
Kaybob South (Amoco, 2 Plants)*	282	264	243	223	203	219	182	74	33	17
Mitsue (Chevron)*	255	258	263	258	227	199	173	85	41	20
Nevis (Gulf)	185	183	177	172	165	156	148	113	77	54
Nipisi (Amoco)*	198	186	167	150	135	121	108	63	37	21
Peco (Conoco)*	76	57	59	62	62	61	61	49	29	17
Ricinus (Amoco)	214	208	201	191	182	176	170	146	117	68
Strachan(Gulf)	177	166	154	144	133	125	117	82	60	44
Turner Valley (Pembina)	76	69	62	56	51	46	42	25	15	9
Waterton (Shell)	231	213	195	180	163	156	150	101	66	40
Wembley (Amoco)*	189	208	190	185	183	180	177	161	145	128
Subtotal	5567	5281	4895	4656	5213	4970	4743	3643	2635	1628
Straddle Plants										
Cochrane (A.N.G.C.)*	542	555	560	570	565	560	555	540	585	750
Ellerslie (Amoco)*	281	280	280	280	280	280	280	280	280	280
Empress (3 plants)*	1691	1745	1860	2015	2060	2125	2170	2295	2430	2390
Fort Saskatchewan (Midwest)*	17	17	17	17	17	17	17	17	17	17
Subtotal	2531	2597	2717	2882	2922	2982	3022	3132	3312	3437
Total[a]	8098	7878	7612	7538	8135	7952	7765	6775	5947	5065

Notes:[*] All or part of the production is entrained in an NGL mix.
[a] These plants accounted for 74 percent of gas plant butanes production in 1989.

Table A8-6
Pentanes Plus Production from Selected Gas Plants

(Thousands of Cubic Metres per Day)

Control Case

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Field Plants										
Bonnie Glen (Esso, 2Plants)	583	550	514	453	403	364	331	237	103	73
Brazeau (Chevron)*	43	49	46	42	37	31	27	21	21	22
Brazeau (Petro-Canada,2 Plants)*	629	646	628	600	580	565	554	453	374	208
Caroline (Shell)	0	0	0	350	2800	2800	2800	2800	2424	1145
Carson Creek (Mobil)	182	195	189	164	138	115	95	35	10	1
Carstairs (Home)	306	264	229	201	173	152	126	79	52	33
Crossfield East (Amoco)	46	42	37	34	31	29	30	33	26	16
Elmworth (Canadian Hunter)	156	144	132	126	123	113	105	76	45	23
Elmworth (Esso)*	132	107	85	69	57	47	40	17	9	4
Ferrier (Amerada)	142	122	106	93	82	73	66	39	23	13
Harmattan Elkton (Mobil)	598	564	564	536	510	485	462	317	162	80
Homeglen-Rimbey (Gulf)	655	616	569	516	472	438	412	320	231	122
Judy Creek (Esso)*	887	872	860	844	813	818	882	851	621	460
Jumping Pound (Shell)	407	398	389	380	372	363	356	230	141	83
Kaybob (Petro-Canada)*	74	77	80	76	74	73	70	59	48	26
Kaybob South (Chevron)*	1217	1162	1108	1044	984	934	790	242	56	11
Kaybob South (Amoco, 2 Plants)*	1101	1058	1013	968	923	937	746	248	84	23
Mitsue (Chevron)*	121	124	126	124	109	95	83	41	20	9
Nevis (Gulf)	183	177	168	160	151	142	134	99	68	48
Nipisi (Amoco)*	123	116	104	93	83	74	67	38	22	12
Peco (Conoco)*	201	215	220	228	232	230	229	188	116	68
Ricinus (Amoco)	238	227	215	201	187	176	165	117	75	44
Strachan (Canterra)	114	112	108	101	95	90	83	59	32	17
Strachan (Gulf)	515	468	427	392	360	332	308	215	156	121
Turner Valley (Pembina)	54	50	45	41	37	34	31	19	11	7
Wapiti (Amoco)	111	83	64	52	44	37	33	17	9	5
Waterton (Shell)	712	650	585	531	481	448	417	277	181	106
Wembley (Amoco)*	484	520	475	460	450	445	440	400	360	325
Subtotal	10014	9608	9086	8879	10801	10440	9882	7527	5480	3105
Straddle Plants										
Cochrane (A.N.G.C.)*	210	215	218	221	218	216	214	210	225	290
Ellerslie (Amoco)*	156	155	155	155	155	155	155	155	155	155
Empress (3 plants)*	695	715	765	830	850	875	890	940	100	980
Fort Saskatchewan (Midwest)*	8	8	8	8	8	8	8	8	8	8
Subtotal	1069	1093	1146	1214	1231	1254	1267	1313	488	1433
Total[a]	11083	10701	10232	10093	12032	11694	11149	8840	5968	4538

Note: [*] All or part of the production is entrained in an NGL mix.
[a] These plants accounted for 58 percent of the pentanes plus production in1989.

Table A8-7
Propane Production from Refineries - Canada and Regions

(Cubic Metres per Day)

Control Case

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Atlantic	418	430	442	442	446	448	449	460	466	470
Quebec	610	633	598	597	598	602	606	614	624	640
Ontario	2080	2085	2153	2166	2191	2210	2229	2309	2397	2485
Prairies	1128	1126	1176	1171	1178	1183	1187	1203	1229	1261
British Columbia	250	252	222	226	229	232	235	247	261	275
Canada Total	4486	4526	4591	4602	4642	4675	4706	4833	4977	5131

Note: [a] Supply is net of energy supply industry own use.

Table A8-8
Butanes Production from Refineries - Canada and Regions

(Cubic Metres per Day)

	Control Case									
	1989	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**2000**	**2005**	**2010**
Atlantic	144	148	152	152	154	155	155	158	161	162
Quebec	132	137	130	129	130	130	131	132	135	139
Ontario	571	572	591	595	601	607	612	634	658	682
Prairies	956	954	997	992	998	1002	1005	1019	1042	1069
British Columbia	221	223	197	199	202	205	208	218	230	243
Canada Total	**2024**	**2034**	**2067**	**2067**	**2085**	**2099**	**2111**	**2161**	**2226**	**2295**

Note: [a] Supply is net of energy supply industry own use.

(Thousands of Cubic Metres per Day)

Control Case

	Supply	Domestic Demand			Potential Exports
	Total	End Use	Miscible Flood Requirements	Total	Total
1990	29.0	18.0	8.3	26.3	2.7
1991	30.0	18.1	10.7	28.8	1.2
1992	32.9	18.2	7.7	25.9	7.0
1993	34.1	18.2	6.5	24.7	9.4
1994	34.8	18.3	2.7	21.0	13.8
1995	35.5	23.6	2.8	26.4	9.1
1996	36.3	23.7	1.4	25.1	11.2
1997	37.0	23.7	1.6	25.3	11.7
1998	37.2	26.4	1.6	28.0	9.2
1999	37.5	26.5	1.9	28.4	9.1
2000	38.0	26.6	2.2	28.8	9.2
2001	38.3	26.6	2.6	29.2	9.1
2002	38.5	26.7	2.6	29.3	9.2
2003	39.4	26.8	2.9	29.7	9.7
2004	40.2	26.9	3.1	30.0	10.2
2005	41.2	27.0	3.4	30.4	10.8
2006	42.1	27.1	3.6	30.7	11.4
2007	43.0	27.2	3.9	31.1	11.9
2008	42.8	27.2	3.9	31.1	11.7
2009	42.7	27.3	4.0	31.3	11.4
2010	41.5	27.4	4.0	31.4	10.1

Table A8-10
Propane Supply and Demand - Canada

(Thousands of Cubic Metres per Day)

Control Case

	Supply	Domestic Demand			Potential Exports
	Total	End Use	Miscible Flood Requirements	Total	Total
1990	26.0	12.4	2.8	15.2	10.8
1991	26.7	12.7	3.0	15.7	11.0
1992	28.9	12.8	2.0	14.8	14.1
1993	30.0	13.0	1.5	14.5	15.5
1994	30.3	13.3	0.7	14.0	16.3
1995	30.6	13.5	0.7	14.2	16.4
1996	30.8	13.7	0.5	14.2	16.6
1997	30.9	13.8	0.5	14.3	16.6
1998	30.8	14.0	0.5	14.5	16.3
1999	30.8	14.1	0.6	14.7	16.1
2000	30.8	14.3	0.7	15.0	15.8
2001	31.0	14.4	0.8	15.2	15.8
2002	31.3	14.6	0.8	15.4	15.9
2003	31.8	14.8	0.8	15.6	16.2
2004	32.4	15.0	0.9	15.9	16.5
2005	33.2	15.2	1.0	16.2	17.0
2006	33.7	15.5	1.1	16.6	17.1
2007	34.4	15.7	1.1	16.8	17.6
2008	34.2	15.9	1.2	17.1	17.1
2009	33.9	16.1	1.2	17.3	16.6
2010	33.5	16.3	1.2	17.5	16.0

Butanes Supply and Demand - Canada

(Thousands of Cubic Metres per Day)

Control Case

	Supply	Domestic Demand				Potential Exports
	Total	End Use	Refinery Requirements	Miscible Flood Requirements	Total	Total
1990	13.1	1.2	2.9	1.3	5.4	7.7
1991	13.3	1.2	3.0	1.3	5.5	7.8
1992	14.4	3.1	3.0	1.0	7.1	7.3
1993	15.4	3.1	3.0	0.9	7.0	8.4
1994	15.6	3.1	3.0	0.3	6.4	9.2
1995	15.8	3.2	3.0	0.3	6.5	9.3
1996	16.1	3.2	3.1	0.3	6.6	9.5
1997	16.2	3.2	3.1	0.3	6.6	9.6
1998	16.2	3.2	3.1	0.3	6.6	9.6
1999	16.1	3.3	3.1	0.3	6.7	9.4
2000	16.1	3.3	3.1	0.3	6.7	9.4
2001	16.3	3.3	3.2	0.4	6.9	9.4
2002	16.5	3.3	3.2	0.4	6.9	9.6
2003	16.9	3.4	3.2	0.4	7.0	9.9
2004	17.4	3.4	3.2	0.5	7.1	10.3
2005	17.9	3.4	3.2	0.5	7.1	10.8
2006	18.3	3.5	3.3	0.6	7.4	10.9
2007	18.8	3.5	3.3	0.6	7.4	11.4
2008	18.6	3.5	3.3	0.6	7.4	11.2
2009	18.5	3.6	3.3	0.6	7.5	11.0
2010	18.3	3.6	3.3	0.6	7.5	10.8

Appendix 9
Table A9-1
Summary of Canada's Coal Resources

(Megatonnes)

Coal Region	Coal Rank[a]	Immediate Interest Assurance[b,c] Measured	Indicated	Inferred	Future Interest Assurance Measured	Indicated	Inferred	Speculative
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Coastal British Columbia								
-Vancouver Island	h - mvb	35	80	200	-	-	300	-
-Queen Charlotte Islands	lvb - an	-	-	10	-	-	-	-
	h - mvb	-	15	10	-	-	-	-
	lig - sub	-	-	50	-	-	-	500
Intermontane British Columbia								
-Northern District	lvb - an	100	500	1000	-	-	-	4000
	h - mvb	30	50	100	-	-	-	100
-Southern District	sub - hvb	40	120	340	-	-	-	-
	lig - sub	450	320	270	-	-	-	-
Rocky Mountains and Foothills								
-Front Ranges								
East Kootenays	h - mvb	1390	1320	4040	-	2700	-	-
Crowsnest	m - lvb	265	140	510	-	200	-	-
	h - mvb	330	170	630	-	-	-	-
Cascade	lvb - an	240	120	455	-	210	-	-
Panther River-Clearwater	lvb - an	-	-	-	15	15	700	-
-Inner Foothills								
Southern District	m - lvb	635	320	1145	-	245	-	-
	h - mvb	150	75	275	-	-	-	-
Northern District	m - lvb	1115	2385	6270	-	100	-	-
-Outer Foothills	sub - hvb	830	740	1955	-	200	-	-
Plains								
-Mannville Group	lig - sub	-	35	100	-	-	30	-
-Belly River/Edmonton/Wapiti	sub - hvb	1240	585	1860	-	820	-	-
	lig - sub	11860	4935	16575	-	14115	-	-
-Paskapoo	sub - hvb	120	60	175	-	25	-	-
-Ravenscrag	lig - sub	1445	2680	3440	165	3910	23510	-
-Deep Coal	sub - hvb	-	-	-	1200	4000	50000	85000

Table A9-1 (continued)
Summary of Canada's Coal Resources

(Megatonnes)

		Immediate Interest			Future Interest			
	Coal	Assurance[b,c]			Assurance			
Coal Region	Rank[a]	Measured	Indicated	Inferred	Measured	Indicated	Inferred	Speculative
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Hudson Bay Lowland								
-Onakawana	lig - sub	170	10	_	(No available estimates)			
Atlantic Provinces	h - mvb	345	365	770	-	1500	215	-
Northern Canada								
-Yukon/District of Mackenzie	lvb - an	-	-	90	(No available estimates of resources of future interest for this region)			
	h - mvb	-	-	150				
	sub - hvb	-	-	350				
	lig - sub	-	-	2290				
-Arctic Archipelago	sub - hvb	-	-	-	-	500	550	4500
	lig - sub	-	-	_	-	7000	7500	31000
Totals	lvb - an	340	620	1555	15	225	700	4000
	m - lvb	2015	2845	7925	-	545	-	-
	h - mvb	2280	2075	6175	-	4200	515	100
	sub - hvb	2230	1505	4680	1200	5545	50550	89500
	lig - sub	13925	7980	22725	165	25025	31040	31500
	All Ranks	20790	15025	43060	1380	35540	82805	125100

Notes: [a] an = anthracite; lvb = low volatile bituminous; mvb = medium volatile bituminous; hvb = high volatile bituminous; sub = subbituminous; lig = lignite.

[b] These coal resource estimates may differ from those of the respective provincial governments because of different resource estimating criteria and parameters used.

[c] Resources shown in this table include reserves.

Source: Coal Resources of Canada, Paper 89-4, Geological Survey of Canada, 1989.

Table A9-2
Coal Exports in 1989 by Destination

(Kilotonnes)

	Thermal	Metallurgical	Total
Japan	1758	17981	19739
South Korea	1471	3693	5164
Brazil	63	1590	1653
United States	82	1117	1199
Taiwan	-	1107	1107
United Kingdom	31	738	769
France	73	553	626
Denmark	575	44	619
Netherlands	-	567	567
Portugal	-	336	336
Pakistan	-	286	286
Chile	-	192	192
West Germany	98	39	137
Sweden	-	134	134
China	-	96	96
Australia	-	63	63
Italy	-	51	51
Belgium	-	6	6
Total	4151	28593	32744

Source: Statistical Review of Coal in Canada: 1989, Energy, Mines and Resources, 1990.

Table A9-3
Historical Data - Coal Production, Imports and Exports - Canada

(Megatonnes)

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
Production										
Bituminous - Thermal	-	-	1.5	1.3	1.7	2.5	2.7	2.3	3.4	4.4
- Metallurgical	8.1 [a]	9.7 [a]	9.9	11.1	10.9	13.3	11.6	13.0	13.8	14.0
Subbituminous [b]	3.5	4.0	4.4	4.5	5.1	6.0	6.4	7.9	8.3	9.6
Lignite [b]	3.4	3.0	3.0	3.7	3.5	3.5	4.7	5.5	5.1	5.0
Total	**15.0**	**16.7**	**18.7**	**20.5**	**21.1**	**25.3**	**25.5**	**28.7**	**30.5**	**33.0**
Imports										
Anthracite	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.4	0.3	0.2
Bituminous - Thermal	11.2	9.6	10.2	7.7	5.2	8.9	7.3	9.0	8.5	10.3
- Metallurgical	6.0	6.1	6.2	7.0	6.8	6.5	7.0	6.1	5.4	7.0
Total	**17.6**	**16.1**	**16.8**	**15.1**	**12.4**	**15.8**	**14.6**	**15.4**	**14.1**	**17.5**
Exports										
Bituminous - Thermal	0.3	0.3	1.0	0.2	0.4	0.8	0.9	0.9	1.0	0.9
- Metallurgical	3.7	6.7	7.6	10.1	10.1	10.6	10.9	11.5	13.0	12.8
Total	**4.0**	**7.0**	**8.5**	**10.3**	**10.5**	**11.4**	**11.9**	**12.4**	**14.0**	**13.7**

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Production										
Bituminous - Thermal	6.0	6.6	8.2	7.4	10.7	9.9	9.8	10.0	10.4	10.7
- Metallurgical	14.1	15.1	14.1	15.1	21.4	24.3	22.4	22.6	28.2	28.1
Subbituminous	10.5	11.6	13.0	14.5	15.4	16.9	17.3	18.5	19.9	20.9
Lignite	6.0	6.8	7.5	7.8	9.9	9.7	8.3	10.0	12.1	10.8
Total	**36.7**	**40.1**	**42.8**	**44.8**	**57.4**	**60.7**	**57.8**	**61.2**	**70.6**	**70.5**
Imports										
Anthracite	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.5
Bituminous - Thermal	9.1	9.2	11.0	8.2	11.5	8.3	6.9	8.5	10.5	8.4
- Metallurgical	6.4	5.4	4.5	6.2	6.6	6.4	5.8	5.8	6.3	5.8
Total	**15.9**	**14.8**	**15.8**	**14.7**	**18.4**	**14.9**	**13.1**	**14.7**	**17.2**	**14.7**
Exports										
Bituminous - Thermal	1.1	1.9	3.0	2.5	4.1	4.9	4.5	4.3	4.1	4.2
- Metallurgical	14.1	13.8	13.0	14.5	21.1	22.5	21.5	22.4	27.6	28.6
Total	**15.3**	**15.7**	**16.0**	**17.0**	**25.1**	**27.4**	**25.9**	**26.7**	**31.7**	**32.7**

Notes: [a] Includes thermal and metallurgical bituminous production.
[b] All subbituminous and lignite production is used for thermal purposes.
Source: Statistical Review of Coal in Canada, Energy, Mines and Resources.

Table A9-4
Coal Supply and Demand - Canada

(Megatonnes)

Control Case

		1990	1991	1992	1993	1995	2000	2005	2010
Domestic Demand	Thermal	41.5	40.9	40.9	41.6	45.3	51.6	60.9	68.6
	Metallurgical	5.8	6.0	6.1	6.4	7.1	7.5	7.9	8.3
	Total	**47.3**	**46.9**	**47.0**	**48.0**	**52.4**	**59.1**	**68.8**	**76.9**
Exports	Thermal	4.3	4.4	4.5	4.7	5.0	5.7	6.7	7.7
	Metallurgical	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6
	Total	**32.9**	**33.0**	**33.1**	**33.3**	**33.6**	**34.3**	**35.3**	**36.3**
Imports	Thermal	7.5	6.6	5.5	4.8	5.3	8.1	12.1	11.4
	Metallurgical	5.8	6.0	6.1	6.4	7.1	7.5	7.9	8.3
	Total	**13.3**	**12.6**	**11.6**	**11.2**	**12.4**	**15.6**	**20.0**	**19.7**
Production	Thermal	38.2	38.7	39.9	41.6	45.0	49.3	55.5	64.9
	Metallurgical	28.6	28.6	28.6	28.6	28.6	28.6	28.6	28.6
	Total	**66.8**	**67.3**	**68.5**	**70.2**	**73.6**	**77.9**	**84.1**	**93.5**

(Petajoules)

1980

History

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	459	22	3	338	498	0	78	0	0	1397
Commercial	301	15	1	257	203	1	0	0	0	779
Petrochemical	94	43	0	0	138	0	0	0	0	275
Industrial	714	24	248	504	509	42	358	0	0	2400
Transportation	0	2	0	2	1958	0	0	0	0	1962
Road	0	2	0	2	1541	0	0	0	0	1545
Rail	0	0	0	0	94	0	0	0	0	94
Air	0	0	0	0	172	0	0	0	0	172
Marine	0	0	0	0	151	0	0	0	0	151
Non-Energy Use	0	0	0	0	250	0	0	0	0	250
Total End Use	**1568**	**105**	**253**	**1101**	**3555**	**43**	**436**	**0**	**0**	**7061**
Own Use and Losses [e]	**134**	**15**	**0**	**115**	**268**	**0**	**0**	**0**	**0**	**532**
Conversions for Domestic Use [f]										
Electricity Generation	25	0	164	-1216	30	0	25	845	126	0
Refinery Propane Production	0	-35	0	0	35	0	0	0	0	0
Refinery Butanes Production	0	-24	0	0	24	0	0	0	0	0
Butane used in Refineries	0	38	0	0	-38	0	0	0	0	0
Steam Production	0	0	10	0	12	-43	0	0	21	0
NGL Production from Reprocessing	99	-99	0	0	0	0	0	0	0	0
Total Conversions	**125**	**-120**	**174**	**-1216**	**64**	**-43**	**25**	**845**	**147**	**0**
Conversion Losses-Domestic										
Electricity Generation	59	0	383	0	74	0	0	0	308	824
Coke Production	0	0	13	0	0	0	0	0	0	13
Steam Production	0	0	0	0	0	0	0	0	1	2
Total Conversion Losses	**59**	**0**	**396**	**0**	**74**	**0**	**0**	**0**	**308**	**838**
Domestic Demand for Primary Energy	**1886**	**0**	**823**	**0**	**3961**	**0**	**461**	**845**	**455**	**8431**
Export Demand										
Total Energy Exports	863	222	450	109	742	0	0	0	0	2386
Conversions for Export [f]										
Electricity	0	0	39	-109	11	0	0	59	0	0
NGL Production Reprocessing	56	-56	0	0	0	0	0	0	0	0
Total Conversions	56	-56	39	-109	11	0	0	59	0	0
Conversion Losses-Export										
Electricity Generation	0	0	66	0	16	0	0	0	0	82
Export Demand for Primary Energy [g]	**919**	**166**	**555**	**0**	**770**	**0**	**0**	**59**	**0**	**2469**
Total Primary Demand [h]	**2805**	**166**	**1378**	**0**	**4731**	**0**	**461**	**904**	**455**	**10900**
Primary Domestic Production	**2764**	**161**	**891**	**0**	**3444**	**0**	**461**	**904**	**455**	**9080**
Primary Energy Imports [h]	**0**	**0**	**476**	**0**	**1344**	**0**	**0**	**0**	**0**	**1820**
Total Primary Supply [i]	**2764**	**161**	**1367**	**0**	**4788**	**0**	**461**	**904**	**455**	**10900**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
	1989 History									
Domestic Demand										
End Use										
Residential	583	21	2	503	285	0	97	0	0	1492
Commercial	373	24	0	382	109	0	0	0	0	888
Petrochemical	172	151	0	0	120	0	0	0	0	443
Industrial	943	28	234	662	327	24	411	0	0	2629
Transportation	2	26	0	3	1918	0	0	0	0	1950
Road	2	26	0	3	1528	0	0	0	0	1560
Rail	0	0	0	0	91	0	0	0	0	91
Air	0	0	0	0	192	0	0	0	0	192
Marine	0	0	0	0	107	0	0	0	0	107
Non-Energy Use	0	0	0	0	224	0	0	0	0	224
Total End Use	**2073**	**251**	**237**	**1550**	**2983**	**24**	**508**	**0**	**0**	**7625**
Own Use and Losses [e]	**193**	**6**	**4**	**158**	**231**	**0**	**0**	**0**	**0**	**592**
Conversions for Domestic Use [f]										
Electricity Generation	54	0	325	-1677	61	0	13	937	287	0
Refinery Propane Production	0	-42	0	0	42	0	0	0	0	0
Refinery Butanes Production	0	-21	0	0	21	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	2	0	1	0	2	-24	0	0	19	0
NGL Production from Reprocessing	224	-224	0	0	0	0	0	0	0	0
Total Conversions	**281**	**-257**	**326**	**-1677**	**96**	**-24**	**13**	**937**	**306**	**0**
Conversion Losses-Domestic										
Electricity Generation	83	0	566	0	111	0	12	0	584	1357
Coke Production	0	0	9	0	0	0	0	0	0	9
Steam Production	0	0	0	0	0	0	0	0	2	3
Total Conversion Losses	**83**	**0**	**575**	**0**	**112**	**0**	**12**	**0**	**586**	**1368**
Domestic Demand for Primary Energy	**2630**	**0**	**1141**	**31**	**3421**	**0**	**532**	**937**	**892**	**9585**
Export Demand										
Total Energy Exports	1432	179	905	57	1953	0	0	0	0	4526
Conversions for Export [f]										
Electricity	0	0	9	-57	5	0	0	36	7	0
NGL Production Reprocessing	16	-16	0	0	0	0	0	0	0	0
Total Conversions	16	-16	9	-57	5	0	0	36	7	0
Conversion Losses-Export										
Electricity Generation	0	0	41	0	15	0	0	0	21	78
Export Demand for Primary Energy [g]	**1448**	**163**	**956**	**0**	**1973**	**0**	**0**	**36**	**29**	**4604**
Total Primary Demand [h]	**4078**	**163**	**2097**	**31**	**5394**	**0**	**532**	**973**	**921**	**14189**
Primary Domestic Production	**4032**	**163**	**1673**	**0**	**3724**	**0**	**532**	**973**	**921**	**12018**
Primary Energy Imports [h]	**46**	**0**	**424**	**31**	**1480**	**0**	**0**	**0**	**0**	**1981**
Total Primary Supply [i]	**4078**	**163**	**2097**	**31**	**5204**	**0**	**532**	**973**	**921**	**13999**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules)

1990

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	566	20	2	501	280	0	96	0	0	1466
Commercial	367	23	0	381	107	0	0	0	0	878
Petrochemical	146	151	0	0	122	0	0	0	0	419
Industrial	921	27	228	660	326	23	411	0	0	2597
Transportation	2	27	0	3	1885	0	0	0	0	1917
Road	2	27	0	3	1502	0	0	0	0	1534
Rail	0	0	0	0	93	0	0	0	0	93
Air	0	0	0	0	185	0	0	0	0	185
Marine	0	0	0	0	106	0	0	0	0	106
Non-Energy Use	0	0	0	0	230	0	0	0	0	230
Total End Use	**2002**	**249**	**230**	**1545**	**2949**	**23**	**508**	**0**	**0**	**7507**
Own Use and Losses [e]	**204**	**6**	**5**	**131**	**227**	**0**	**0**	**0**	**0**	**574**
Conversions for Domestic Use [f]										
Electricity Generation	37	0	256	-1621	51	0	9	1027	240	0
Refinery Propane Production	0	-42	0	0	42	0	0	0	0	0
Refinery Butanes Production	0	-21	0	0	21	0	0	0	0	0
Butane used in Refineries	0	30	0	0	-30	0	0	0	0	0
Steam Production	1	0	0	0	1	-23	0	0	21	0
NGL Production from Reprocessing	222	-222	0	0	0	0	0	0	0	0
Total Conversions	**261**	**-255**	**257**	**-1621**	**86**	**-23**	**9**	**1027**	**261**	**0**
Conversion Losses-Domestic										
Electricity Generation	49	0	536	0	93	0	17	0	565	1259
Coke Production	0	0	8	0	0	0	0	0	0	8
Steam Production	0	0	0	0	0	0	0	0	5	6
Total Conversion Losses	**49**	**0**	**545**	**0**	**93**	**0**	**17**	**0**	**570**	**1273**
Domestic Demand for Primary Energy	**2517**	**0**	**1037**	**56**	**3354**	**0**	**533**	**1027**	**831**	**9355**
Export Demand										
Total Energy Exports	1515	181	908	59	1935	0	0	0	0	4599
Conversions for Export [f]										
Electricity	3	0	17	-59	3	0	0	28	9	0
NGL Production Reprocessing	16	-16	0	0	0	0	0	0	0	0
Total Conversions	19	-16	17	-59	3	0	0	28	9	0
Conversion Losses-Export										
Electricity Generation	12	0	27	0	7	0	0	0	19	66
Export Demand for Primary Energy [g]	**1545**	**165**	**952**	**0**	**1946**	**0**	**0**	**28**	**28**	**4664**
Total Primary Demand [h]	**4062**	**165**	**1988**	**56**	**5301**	**0**	**533**	**1055**	**859**	**14019**
Primary Domestic Production	**4034**	**165**	**1604**	**0**	**3736**	**0**	**533**	**1055**	**859**	**11986**
Primary Energy Imports [h]	**28**	**0**	**385**	**56**	**1436**	**0**	**0**	**0**	**0**	**1905**
Total Primary Supply [i]	**4062**	**165**	**1988**	**56**	**5172**	**0**	**533**	**1055**	**859**	**13890**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)	1991									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	599	21	2	516	285	0	99	0	0	1521
Commercial	385	24	0	396	109	0	0	0	0	914
Petrochemical	158	152	0	0	124	0	0	0	0	435
Industrial	950	27	235	674	318	23	408	0	0	2635
Transportation	3	28	0	3	1872	0	0	0	0	1906
Road	3	28	0	3	1484	0	0	0	0	1518
Rail	0	0	0	0	92	0	0	0	0	92
Air	0	0	0	0	186	0	0	0	0	186
Marine	0	0	0	0	109	0	0	0	0	109
Non-Energy Use	0	0	0	0	234	0	0	0	0	234
Total End Use	**2094**	**252**	**237**	**1589**	**2940**	**24**	**507**	**0**	**0**	**7644**
Own Use and Losses [e]	**215**	**7**	**5**	**130**	**224**	**0**	**0**	**0**	**0**	**580**
Conversions for Domestic Use [f]										
Electricity Generation	27	0	243	-1683	39	0	11	1048	315	0
Refinery Propane Production	0	-43	0	0	43	0	0	0	0	0
Refinery Butanes Production	0	-22	0	0	22	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-24	0	0	21	0
NGL Production from Reprocessing	225	-225	0	0	0	0	0	0	0	0
Total Conversions	**253**	**-259**	**243**	**-1683**	**74**	**-24**	**11**	**1048**	**336**	**0**
Conversion Losses-Domestic										
Electricity Generation	23	0	515	0	68	0	20	0	752	1379
Coke Production	0	0	9	0	0	0	0	0	0	9
Steam Production	0	0	0	0	0	0	0	0	5	6
Total Conversion Losses	**24**	**0**	**524**	**0**	**68**	**0**	**20**	**0**	**757**	**1393**
Domestic Demand for Primary Energy	**2586**	**0**	**1009**	**36**	**3306**	**0**	**538**	**1048**	**1093**	**9617**
Export Demand										
Total Energy Exports	1693	191	911	60	1872	0	0	0	0	4727
Conversions for Export [f]										
Electricity	0	0	16	-60	4	0	0	33	7	0
NGL Production Reprocessing	26	-26	0	0	0	0	0	0	0	0
Total Conversions	26	-26	16	-60	4	0	0	33	7	0
Conversion Losses-Export										
Electricity Generation	0	0	28	0	6	0	0	0	16	49
Export Demand for Primary Energy [g]	**1719**	**165**	**955**	**0**	**1881**	**0**	**0**	**33**	**23**	**4776**
Total Primary Demand [h]	**4306**	**165**	**1964**	**36**	**5187**	**0**	**538**	**1082**	**1117**	**14394**
Primary Domestic Production	**4281**	**165**	**1599**	**0**	**3647**	**0**	**538**	**1082**	**1117**	**12427**
Primary Energy Imports [h]	**25**	**0**	**365**	**36**	**1517**	**0**	**0**	**0**	**0**	**1943**
Total Primary Supply [i]	**4306**	**165**	**1964**	**36**	**5164**	**0**	**538**	**1082**	**1117**	**14370**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules) 1992

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	602	21	2	523	279	0	99	0	0	1525
Commercial	388	24	0	402	109	0	0	0	0	923
Petrochemical	175	173	0	0	126	0	0	0	0	474
Industrial	969	28	241	690	325	24	410	0	0	2687
Transportation	4	28	0	4	1889	0	0	0	0	1925
Road	4	28	0	4	1486	0	0	0	0	1522
Rail	0	0	0	0	95	0	0	0	0	95
Air	0	0	0	0	193	0	0	0	0	193
Marine	0	0	0	0	115	0	0	0	0	115
Non-Energy Use	0	0	0	0	237	0	0	0	0	237
Total End Use	**2138**	**274**	**243**	**1619**	**2965**	**24**	**509**	**0**	**0**	**7771**
Own Use and Losses [e]	**226**	**7**	**5**	**137**	**225**	**0**	**0**	**0**	**0**	600
Conversions for Domestic Use [f]										
Electricity Generation	29	0	233	-1737	37	0	11	1072	355	0
Refinery Propane Production	0	-43	0	0	43	0	0	0	0	0
Refinery Butanes Production	0	-22	0	0	22	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-24	0	0	21	0
NGL Production from Reprocessing	246	-246	0	0	0	0	0	0	0	0
Total Conversions	**276**	**-280**	**233**	**-1737**	**73**	**-24**	**11**	**1072**	377	0
Conversion Losses-Domestic										
Electricity Generation	24	0	481	0	63	0	22	0	828	1418
Coke Production	0	0	9	0	0	0	0	0	0	9
Steam Production	0	0	0	0	0	0	0	0	5	6
Total Conversion Losses	**24**	**0**	**490**	**0**	**63**	**0**	**22**	**0**	833	1432
Domestic Demand for Primary Energy	**2665**	**0**	**971**	**19**	**3326**	**0**	**542**	**1072**	1210	9804
Export Demand										
Total Energy Exports	1941	252	914	108	1886	0	0	0	0	5101
Conversions for Export [f]										
Electricity	0	0	27	-108	4	0	0	67	9	0
NGL Production Reprocessing	30	-30	0	0	0	0	0	0	0	0
Total Conversions	30	-30	27	-108	4	0	0	67	9	0
Conversion Losses-Export										
Electricity Generation	0	0	53	0	7	0	0	0	20	80
Export Demand for Primary Energy [g]	**1971**	**222**	**994**	**0**	**1898**	**0**	**0**	**67**	29	5181
Total Primary Demand [h]	**4635**	**222**	**1966**	**19**	**5224**	**0**	**542**	**1139**	1238	14985
Primary Domestic Production	**4614**	**222**	**1627**	**0**	**3581**	**0**	**542**	**1139**	1238	12963
Primary Energy Imports [h]	**21**	**0**	**339**	**19**	**1608**	**0**	**0**	**0**	0	1987
Total Primary Supply [i]	**4635**	**222**	**1966**	**19**	**5189**	**0**	**542**	**1139**	1238	14950

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules) 1993

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	605	21	2	530	272	0	99	0	0	1530
Commercial	390	24	0	406	108	0	0	0	0	928
Petrochemical	178	174	0	0	128	0	0	0	0	479
Industrial	1008	29	252	716	337	25	413	0	0	2779
Transportation	5	29	0	4	1904	0	0	0	0	1941
Road	5	29	0	4	1491	0	0	0	0	1528
Rail	0	0	0	0	97	0	0	0	0	97
Air	0	0	0	0	197	0	0	0	0	197
Marine	0	0	0	0	119	0	0	0	0	119
Non-Energy Use	0	0	0	0	243	0	0	0	0	243
Total End Use	**2185**	**276**	**254**	**1655**	**2992**	**25**	**512**	**0**	**0**	**7900**
Own Use and Losses [e]	**230**	**7**	**5**	**141**	**228**	**0**	**0**	**0**	**0**	**611**
Conversions for Domestic Use [f]										
Electricity Generation	31	0	229	-1796	39	0	13	1086	398	0
Refinery Propane Production	0	-43	0	0	43	0	0	0	0	0
Refinery Butanes Production	0	-22	0	0	22	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-25	0	0	22	0
NGL Production from Reprocessing	249	-249	0	0	0	0	0	0	0	0
Total Conversions	**282**	**-283**	**229**	**-1796**	**75**	**-25**	**13**	**1086**	**420**	**0**
Conversion Losses-Domestic										
Electricity Generation	25	0	470	0	65	0	24	0	907	1493
Coke Production	0	0	9	0	0	0	0	0	0	9
Steam Production	0	0	0	0	0	0	0	0	6	6
Total Conversion Losses	**26**	**0**	**480**	**0**	**66**	**0**	**24**	**0**	**913**	**1508**
Domestic Demand for Primary Energy	**2723**	**0**	**968**	**0**	**3360**	**0**	**550**	**1086**	**1333**	**10020**
Export Demand										
Total Energy Exports	1953	295	919	138	1801	0	0	0	0	5106
Conversions for Export [f]										
Electricity	0	0	38	-138	4	0	0	87	9	0
NGL Production Reprocessing	31	-31	0	0	0	0	0	0	0	0
Total Conversions	31	-31	38	-138	4	0	0	87	9	0
Conversion Losses-Export										
Electricity Generation	0	0	68	0	7	0	0	0	19	95
Export Demand for Primary Energy [g]	**1984**	**264**	**1025**	**0**	**1813**	**0**	**0**	**87**	**28**	**5201**
Total Primary Demand [h]	**4707**	**264**	**1993**	**0**	**5174**	**0**	**550**	**1173**	**1361**	**15221**
Primary Domestic Production	**4670**	**264**	**1664**	**0**	**3524**	**0**	**550**	**1173**	**1361**	**13205**
Primary Energy Imports [h]	**36**	**0**	**329**	**0**	**1627**	**0**	**0**	**0**	**0**	**1991**
Total Primary Supply [i]	**4706**	**264**	**1993**	**0**	**5151**	**0**	**550**	**1173**	**1361**	**15197**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules) 1994

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	609	21	2	536	266	0	99	0	0	1534
Commercial	394	24	0	411	108	0	0	0	0	936
Petrochemical	180	175	0	0	130	0	0	0	0	485
Industrial	1038	29	266	743	352	26	418	0	0	2872
Transportation	5	29	0	4	1918	0	0	0	0	1957
Road	5	29	0	4	1497	0	0	0	0	1536
Rail	0	0	0	0	98	0	0	0	0	98
Air	0	0	0	0	200	0	0	0	0	200
Marine	0	0	0	0	122	0	0	0	0	122
Non-Energy Use	0	0	0	0	249	0	0	0	0	249
Total End Use	**2227**	**279**	**268**	**1694**	**3023**	**26**	**517**	**0**	**0**	**8033**
Own Use and Losses [e]	**235**	**7**	**5**	**143**	**230**	**0**	**0**	**0**	**0**	**620**
Conversions for Domestic Use [f]										
Electricity Generation	34	0	244	-1837	40	0	14	1098	406	0
Refinery Propane Production	0	-44	0	0	44	0	0	0	0	0
Refinery Butanes Production	0	-22	0	0	22	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-26	0	0	23	0
NGL Production from Reprocessing	251	-251	0	0	0	0	0	0	0	0
Total Conversions	**287**	**-286**	**244**	**-1837**	**77**	**-26**	**14**	**1098**	**429**	**0**
Conversion Losses-Domestic										
Electricity Generation	27	0	482	0	65	0	26	0	903	1503
Coke Production	0	0	10	0	0	0	0	0	0	10
Steam Production	0	0	0	0	0	0	0	0	6	6
Total Conversion Losses	**28**	**0**	**492**	**0**	**65**	**0**	**26**	**0**	**908**	**1520**
Domestic Demand for Primary Energy	**2775**	**0**	**1009**	**0**	**3395**	**0**	**557**	**1098**	**1338**	**10172**
Export Demand										
Total Energy Exports	2007	340	922	163	1727	0	0	0	0	5159
Conversions for Export [f]										
Electricity	0	0	39	-163	4	0	0	112	7	0
NGL Production Reprocessing	34	-34	0	0	0	0	0	0	0	0
Total Conversions	34	-34	39	-163	4	0	0	112	7	0
Conversion Losses-Export										
Electricity Generation	0	0	75	0	8	0	0	0	17	99
Export Demand for Primary Energy [g]	**2041**	**306**	**1036**	**0**	**1739**	**0**	**0**	**112**	**24**	**5258**
Total Primary Demand [h]	**4817**	**306**	**2045**	**0**	**5135**	**0**	**557**	**1210**	**1362**	**15431**
Primary Domestic Production	**4766**	**306**	**1702**	**0**	**3472**	**0**	**557**	**1210**	**1362**	**13374**
Primary Energy Imports [h]	**51**	**0**	**343**	**0**	**1641**	**0**	**0**	**0**	**0**	**2035**
Total Primary Supply [i]	**4817**	**306**	**2045**	**0**	**5113**	**0**	**557**	**1210**	**1362**	**15409**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules)

	1995									
	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	613	21	2	541	260	0	100	0	0	1537
Commercial	398	24	0	417	107	0	0	0	0	946
Petrochemical	183	211	0	0	133	0	0	0	0	526
Industrial	1067	30	275	767	363	26	421	0	0	2950
Transportation	6	30	0	4	1932	0	0	0	0	1973
Road	6	30	0	4	1505	0	0	0	0	1546
Rail	0	0	0	0	100	0	0	0	0	100
Air	0	0	0	0	203	0	0	0	0	203
Marine	0	0	0	0	125	0	0	0	0	125
Non-Energy Use	0	0	0	0	254	0	0	0	0	254
Total End Use	**2267**	**317**	**277**	**1729**	**3050**	**26**	**521**	**0**	**0**	**8187**
Own Use and Losses [e]	**239**	**7**	**5**	**146**	**231**	**0**	**0**	**0**	**0**	**628**
Conversions for Domestic Use [f]										
Electricity Generation	38	0	268	-1875	33	0	15	1107	415	0
Refinery Propane Production	0	-44	0	0	44	0	0	0	0	0
Refinery Butanes Production	0	-22	0	0	22	0	0	0	0	0
Butane used in Refineries	0	31	0	0	-31	0	0	0	0	0
Steam Production	1	0	0	0	1	-26	0	0	24	0
NGL Production from Reprocessing	289	-289	0	0	0	0	0	0	0	0
Total Conversions	**328**	**-324**	**268**	**-1875**	**69**	**-26**	**15**	**1107**	**439**	**0**
Conversion Losses-Domestic										
Electricity Generation	29	0	514	0	51	0	27	0	894	1516
Coke Production	0	0	10	0	0	0	0	0	0	10
Steam Production	0	0	0	0	0	0	0	0	6	7
Total Conversion Losses	**30**	**0**	**524**	**0**	**51**	**0**	**27**	**0**	**900**	**1533**
Domestic Demand for Primary Energy	**2864**	**0**	**1074**	**0**	**3401**	**0**	**563**	**1107**	**1339**	**10348**
Export Demand										
Total Energy Exports	2061	311	927	179	1655	0	0	0	0	5133
Conversions for Export [f]										
Electricity	0	0	42	-179	5	0	0	125	7	0
NGL Production Reprocessing	2	-2	0	0	0	0	0	0	0	0
Total Conversions	2	-2	42	-179	5	0	0	125	7	0
Conversion Losses-Export										
Electricity Generation	0	0	79	0	9	0	0	0	16	104
Export Demand for Primary Energy [g]	**2064**	**309**	**1048**	**0**	**1669**	**0**	**0**	**125**	**23**	**5237**
Total Primary Demand [h]	**4927**	**309**	**2122**	**0**	**5070**	**0**	**563**	**1231**	**1362**	**15585**
Primary Domestic Production	**4861**	**309**	**1758**	**0**	**3419**	**0**	**563**	**1231**	**1362**	**13504**
Primary Energy Imports [h]	**66**	**0**	**364**	**0**	**1631**	**0**	**0**	**0**	**0**	**2061**
Total Primary Supply [i]	**4927**	**309**	**2122**	**0**	**5050**	**0**	**563**	**1231**	**1362**	**15565**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules) 2000

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	634	22	1	571	236	0	100	0	0	1565
Commercial	417	24	0	446	107	0	0	0	0	994
Petrochemical	196	235	0	0	145	0	0	0	0	576
Industrial	1156	31	291	847	429	28	422	0	0	3204
Transportation	10	33	0	6	2001	0	0	0	0	2050
Road	10	33	0	6	1548	0	0	0	0	1597
Rail	0	0	0	0	105	0	0	0	0	105
Air	0	0	0	0	217	0	0	0	0	217
Marine	0	0	0	0	131	0	0	0	0	131
Non-Energy Use	0	0	0	0	280	0	0	0	0	280
Total End Use	**2413**	**346**	**292**	**1869**	**3197**	**28**	**523**	**0**	**0**	**8668**
Own Use and Losses [e]	**252**	**8**	**6**	**143**	**241**	**0**	**0**	**0**	**0**	**649**
Conversions for Domestic Use [f]										
Electricity Generation	46	0	330	-2000	32	0	17	1176	399	0
Refinery Propane Production	0	-45	0	0	45	0	0	0	0	0
Refinery Butanes Production	0	-23	0	0	23	0	0	0	0	0
Butane used in Refineries	0	32	0	0	-32	0	0	0	0	0
Steam Production	1	0	0	0	1	-28	0	0	25	0
NGL Production from Reprocessing	317	-317	0	0	0	0	0	0	0	0
Total Conversions	**364**	**-353**	**330**	**-2000**	**69**	**-28**	**17**	**1176**	**423**	**0**
Conversion Losses-Domestic										
Electricity Generation	37	0	611	0	45	0	29	0	851	1573
Coke Production	0	0	11	0	0	0	0	0	0	11
Steam Production	0	0	0	0	0	0	0	0	6	7
Total Conversion Losses	**37**	**0**	**622**	**0**	**46**	**0**	**29**	**0**	**857**	**1591**
Domestic Demand for Primary Energy	**3067**	**0**	**1250**	**13**	**3553**	**0**	**568**	**1176**	**1281**	**10908**
Export Demand										
Total Energy Exports	2220	307	947	163	2190	0	0	0	0	5827
Conversions for Export [f]										
Electricity	0	0	36	-163	4	0	0	118	5	0
NGL Production Reprocessing	-10	10	0	0	0	0	0	0	0	0
Total Conversions	-10	10	36	-163	4	0	0	118	5	0
Conversion Losses-Export										
Electricity Generation	0	0	82	0	8	0	0	0	13	103
Export Demand for Primary Energy [g]	**2210**	**317**	**1065**	**0**	**2202**	**0**	**0**	**118**	**18**	**5930**
Total Primary Demand [h]	**5277**	**317**	**2315**	**13**	**5755**	**0**	**568**	**1294**	**1299**	**16838**
Primary Domestic Production	**5125**	**317**	**1862**	**0**	**3634**	**0**	**568**	**1294**	**1299**	**14099**
Primary Energy Imports [h]	**152**	**0**	**453**	**13**	**2078**	**0**	**0**	**0**	**0**	**2696**
Total Primary Supply [i]	**5277**	**317**	**2315**	**13**	**5712**	**0**	**568**	**1294**	**1299**	**16795**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Table A10-1 (Continued)
Total Energy Balance

(Petajoules) — 2005

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	647	23	1	609	219	0	102	0	0	1600
Commercial	437	25	0	477	105	0	0	0	0	1044
Petrochemical	211	242	0	0	158	0	0	0	0	611
Industrial	1163	33	395	929	542	29	427	0	0	3519
Transportation	14	36	0	7	2056	0	0	0	0	2114
Road	14	36	0	7	1590	0	0	0	0	1647
Rail	0	0	0	0	106	0	0	0	0	106
Air	0	0	0	0	228	0	0	0	0	228
Marine	0	0	0	0	133	0	0	0	0	133
Non-Energy Use	0	0	0	0	310	0	0	0	0	310
Total End Use	**2473**	**358**	**396**	**2022**	**3391**	**29**	**528**	**0**	**0**	**9198**
Own Use and Losses [e]	**263**	**8**	**6**	**144**	**257**	**0**	**0**	**0**	**0**	**678**
Conversions for Domestic Use [f]										
Electricity Generation	56	0	386	-2149	38	0	17	1268	385	0
Refinery Propane Production	0	-46	0	0	46	0	0	0	0	0
Refinery Butanes Production	0	-23	0	0	23	0	0	0	0	0
Butane used in Refineries	0	33	0	0	-33	0	0	0	0	0
Steam Production	2	0	0	0	2	-29	0	0	26	0
NGL Production from Reprocessing	326	-326	0	0	0	0	0	0	0	0
Total Conversions	**383**	**-362**	**386**	**-2149**	**75**	**-29**	**17**	**1268**	**412**	**0**
Conversion Losses-Domestic										
Electricity Generation	53	0	693	0	57	0	29	0	821	1653
Coke Production	0	0	12	0	0	0	0	0	0	12
Steam Production	0	0	0	0	0	0	0	0	7	7
Total Conversion Losses	**54**	**0**	**704**	**0**	**57**	**0**	**29**	**0**	**827**	**1672**
Domestic Demand for Primary Energy	**3172**	**5**	**1492**	**18**	**3781**	**0**	**574**	**1268**	**1239**	**11548**
Export Demand										
Total Energy Exports	2503	343	974	176	2424	0	0	0	0	6420
Conversions for Export [f]										
Electricity	0	0	31	-176	3	0	0	136	6	0
NGL Production Reprocessing	0	0	0	0	0	0	0	0	0	0
Total Conversions	0	0	31	-176	3	0	0	136	6	0
Conversion Losses-Export										
Electricity Generation	0	0	77	0	5	0	0	0	12	94
Export Demand for Primary Energy [g]	**2503**	**343**	**1082**	**0**	**2433**	**0**	**0**	**136**	**18**	**6514**
Total Primary Demand [h]	**5676**	**348**	**2573**	**18**	**6214**	**0**	**574**	**1403**	**1257**	**18062**
Primary Domestic Production	**5434**	**348**	**1998**	**0**	**3949**	**0**	**574**	**1403**	**1257**	**14963**
Primary Energy Imports [h]	**241**	**0**	**575**	**18**	**2213**	**0**	**0**	**0**	**0**	**3047**
Total Primary Supply [i]	**5675**	**348**	**2573**	**18**	**6162**	**0**	**574**	**1403**	**1257**	**18010**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

(Petajoules) 2010

	Natural Gas	NGL [a]	Coal, Coke Coke Gas	Electricity	Oil [b]	Steam	Renewable	Hydro [c]	Nuclear [d]	Total
Domestic Demand										
End Use										
Residential	664	24	1	647	206	0	103	0	0	1645
Commercial	457	25	0	510	104	0	0	0	0	1095
Petrochemical	227	250	0	0	173	0	0	0	0	650
Industrial	1117	35	495	1023	724	32	435	0	0	3861
Transportation	18	39	0	9	2118	0	0	0	0	2184
Road	18	39	0	9	1628	0	0	0	0	1694
Rail	0	0	0	0	108	0	0	0	0	109
Air	0	0	0	0	244	0	0	0	0	244
Marine	0	0	0	0	137	0	0	0	0	137
Non-Energy Use	0	0	0	0	344	0	0	0	0	344
Total End Use	**2483**	**373**	**496**	**2189**	**3668**	**32**	**538**	**0**	**0**	**9779**
Own Use and Losses [e]	**258**	**9**	**6**	**143**	**281**	**0**	**0**	**0**	**0**	**697**
Conversions for Domestic Use [f]										
Electricity Generation	61	0	403	-2315	50	0	17	1354	431	0
Refinery Propane Production	0	-48	0	0	48	0	0	0	0	0
Refinery Butanes Production	0	-24	0	0	24	0	0	0	0	0
Butane used in Refineries	0	34	0	0	-34	0	0	0	0	0
Steam Production	2	0	0	0	2	-32	0	0	28	0
NGL Production from Reprocessing	325	-325	0	0	0	0	0	0	0	0
Total Conversions	**388**	**-363**	**403**	**-2315**	**90**	**-32**	**17**	**1354**	**460**	**0**
Conversion Losses-Domestic										
Electricity Generation	59	0	749	0	80	0	30	0	922	1840
Coke Production	0	0	12	0	0	0	0	0	0	12
Steam Production	0	0	0	0	0	0	0	0	7	8
Total Conversion Losses	**59**	**0**	**761**	**0**	**81**	**0**	**30**	**0**	**929**	**1860**
Domestic Demand for Primary Energy	**3189**	**18**	**1665**	**17**	**4120**	**0**	**585**	**1354**	**1388**	**12336**
Export Demand										
Total Energy Exports	2492	330	1002	168	2708	0	0	0	0	6700
Conversions for Export [f]										
Electricity	0	0	36	-168	2	0	0	125	6	0
NGL Production Reprocessing	0	0	0	0	0	0	0	0	0	0
Total Conversions	0	0	36	-168	2	0	0	125	6	0
Conversion Losses-Export										
Electricity Generation	0	0	64	0	2	0	0	0	12	79
Export Demand for Primary Energy [g]	**2492**	**330**	**1103**	**0**	**2712**	**0**	**0**	**125**	**18**	**6780**
Total Primary Demand [h]	**5681**	**348**	**2768**	**17**	**6832**	**0**	**585**	**1479**	**1406**	**19115**
Primary Domestic Production	**5416**	**348**	**2199**	**0**	**4320**	**0**	**585**	**1479**	**1406**	**15753**
Primary Energy Imports [h]	**264**	**0**	**569**	**17**	**2421**	**0**	**0**	**0**	**0**	**3270**
Total Primary Supply [i]	**5680**	**348**	**2768**	**17**	**6741**	**0**	**585**	**1479**	**1406**	**19024**

Notes: [a] Natural gas liquids domestic demand is assumed to be met from refineries, reprocessing and primary supply in that order.
[b] Differences in oil supply and disposition result from differences in conversion factors.
[c] Hydro is converted at 3.6 GJ/MWh.
[d] Nuclear is converted at 12.1 GJ/MWh.
[e] Includes own use and losses associated with domestic end use and exports. Own use includes pipeline fuel and reprocessing fuel for natural gas. Energy industry fuel for NGL, losses in the production of coke for coal, transmission and distribution losses for electricity and refinery and terminal consumption for oil.
[f] A negative number indicates conversion of another energy form into the subject energy form. A positive number indicates the subject energy source is converted to some other energy form.
[g] Includes oil products exports.
[h] Includes imports of oil products.
[i] Demand and Supply may not balance due to inventory changes.
[j] To derive primary demand equivalent with table A4 - 3, subtract production from reprocessing from domestic demand for primary energy.

Appendix 11
Table A11-1
CO2 Gas Emission Factors

	Carbon	Heat Content	Carbon Tonnes/TJ	CO2 Tonnes/TJ
Natural Gas	512.46 g/M3	37.88 MJ/M3	13.53	49.61
Motor Gasoline	642.60 g/l	34.66 GJ/M3	18.54	67.98
Kerosene	695.20 g/l	37.68 GJ/M3	18.45	67.65
Aviation Gas	634.20 g/l	33.52 GJ/M3	18.92	69.37
Propane (LPG's)	416.65 g/l	25.53 GJ/M3	16.32	59.84
Diesel Oil	745.75 g/l	38.68 GJ/M3	19.28	70.69
Light Oil	771.28 g/l	38.68 GJ/M3	19.94	73.11
Heavy Oil		41.73 GJ/M3	20.18	74.00
Aviation Turbo	694.17 g/l	35.93 GJ/M3	19.32	70.84
Petroleum Coke	898.92 g/Kg	32.96 GJ/Tonne	27.27	100.00
Other Oil Products				67.50
Wood	400.00 g/KG	19.80 GJ/Tonne	20.20	74.08
Wood Wastes	400.00 g/KG	18.00 GJ/Tonne	22.22	81.48
Pulping Liquor	410.00 g/KG	14.00 GJ/Tonne	29.29	107.38
Coal				
Imp. Bituminous	702.97 g/KG	29.00 GJ/Tonne	24.24	88.88
Cdn. Bituminous	692.95 g/KG	27.60 GJ/Tonne	25.11	92.06
Sub - Bituminous	507.63 g/KG	18.80 GJ/Tonne	27.00	99.01
Lignite	425.66 g/KG	14.40 GJ/Tonne	29.56	108.39
Anthracite	702.97 g/KG	27.70 GJ/Tonne	25.38	93.05
Estimated Emission Factors				
Municipal Wastes	250.00 g/KG	14.00 GJ/Tonne	17.86	65.48
Coke and Coke Oven Gases		28.83 GJ/Tonne		86.04
		18.61 GJ/M3		

Note: Factors derived by NEB in consultation with Energy, Mines and Resources and Environment Canada.

Table A11-2
Nitrogen Oxides (NOX) Emission Factors

Tonnes / PJ

	Residential	Commercial	Industrial	Transportation
Renewables (Excluding Wood)	113.00	113.00		
Natural Gas	42.30	42.30	59.20	
Propane - Transportation	42.70	42.70	59.90	
LPG's	42.70	42.70	59.90	
Gasoline				(1)
Kerosene	61.00	63.70	63.70	
Aviation Gasoline		223.00		223.00
Aviation Turbo		208.00		208.00
Light Fuel Oil	59.50	62.00	62.00	
Diesel	1030.00	1290.00	1080.00	(1)
Rail				1440.00
Marine				235.00
Heavy Fuel Oil	158.00	158.00	158.00	200.00
Petroleum Coke			241.00	
Non - Energy - Refined Petroleum Products			0.00	
Industry Own Use - Refined Petroleum Products			118.00	
Wood and Wood Waste	41.00		113.00	
Spent Pulping Liquor (Industry)			113.00	
Coal	250.00	250.00	250.00	
Coke and Coke Oven Gas			237.00	

Notes: Factors derived by NEB in consultation with Energy, Mines and Resources and Environment Canada.

(1) For detailed gasoline and diesel transportation emissions factors, see below.

Table 11-2 (Continued)
Transportation (NOX) Emission Factors

	Atlantic	Quebec	Ontario	Manitoba	Saskatchewan	Alberta	British Columbia & Territories
			Grams per Mile				
			Light Duty Trucks - Mogas				
1989	2.64	2.63	2.62	2.74	2.76	2.71	2.55
1990	2.41	2.40	2.39	2.51	2.53	2.48	2.33
1995	1.79	1.78	1.77	1.88	1.89	1.84	1.72
2000	1.49	1.48	1.48	1.57	1.58	1.53	1.43
2005	1.40	1.39	1.39	1.47	1.48	1.44	1.34
2010	1.40	1.39	1.39	1.47	1.48	1.44	1.34
			Medium / Heavy Duty Trucks - Mogas				
1989	7.01	6.98	6.94	7.11	7.14	7.10	6.84
1990	6.91	6.88	6.84	7.00	7.03	7.00	6.74
1995	5.79	5.76	5.72	5.85	5.88	5.88	5.64
2000	5.48	5.46	5.42	5.54	5.58	5.29	5.34
2005	5.41	5.38	5.34	5.46	5.50	5.50	5.26
2010	5.41	5.38	5.34	5.46	5.50	5.50	5.26
			Cars - Mogas				
1989	2.13	2.12	2.26	2.63	2.71	2.57	2.53
1990	1.88	1.88	2.03	2.41	2.50	2.35	2.33
1995	1.15	1.14	1.26	1.55	1.62	1.51	1.52
2000	0.96	0.95	1.01	1.17	1.20	1.14	1.12
2005	0.94	0.93	0.96	1.07	1.09	1.04	1.01
2010	0.94	0.93	0.96	1.07	1.09	1.04	1.01
			Light Duty Trucks - DFO				
1989	1.72	1.72	1.72	1.72	1.72	1.72	1.72
1990	1.68	1.68	1.68	1.68	1.68	1.68	1.68
1995	1.32	1.32	1.32	1.32	1.32	1.32	1.32
2000	1.31	1.31	1.31	1.31	1.31	1.31	1.31
2005	1.32	1.32	1.32	1.32	1.32	1.32	1.32
2010	1.32	1.32	1.32	1.32	1.32	1.32	1.32
			Medium / Heavy Duty Trucks - DFO				
1989	19.05	20.97	20.97	20.97	20.97	20.97	20.97
1990	20.13	20.13	20.13	20.13	20.13	20.13	20.13
1995	11.74	11.74	11.74	11.74	11.74	11.74	11.74
2000	9.48	9.48	9.48	9.48	9.48	9.48	9.48
2005	8.93	8.93	8.93	8.93	8.93	8.93	8.93
2010	8.93	8.93	8.93	8.93	8.93	8.93	8.93
			Cars - DFO				
1989	1.46	1.46	1.46	1.46	1.46	1.46	1.46
1990	1.43	1.43	1.43	1.43	1.43	1.43	1.43
1995	1.14	1.14	1.14	1.14	1.14	1.14	1.14
2000	1.15	1.15	1.15	1.15	1.15	1.15	1.15
2005	1.18	1.18	1.18	1.18	1.18	1.18	1.18
2010	1.18	1.18	1.18	1.18	1.18	1.18	1.18

Note: Factors derived with assistance of Environment Canada, based on NEB projections of car and truck vintage and stock.

Table A11-3
Volatile Organic Compounds (VOC) Emission Factors

Tonnes / PJ

	Residential	Commercial	Industrial	Transportation
Renewables (Excluding Wood)	56.70	56.70		
Natural Gas	2.22	2.22	1.16	
Propane - Transportation	2.22	2.22	1.11	
LPG's	2.22	2.22	1.11	
Gasoline				(1)
Kerosene	2.26	1.06	0.64	
Aviation Gasoline				67.70
Aviation Turbo				63.20
Light Fuel Oil	2.20	1.04	0.62	
Diesel	179.00	100.00	88.20	(1)
Rail				69.80
Marine				392.00
Heavy Fuel Oil	3.35	3.35	2.88	363.00
Petroleum Coke			1.51	
Non - Energy - Refined Petroleum Products			0.00	
Industry Own Use - Refined Petroleum Products			1.24	
Wood and Wood Waste	1169.00		56.70	
Spent Pulping Liquor (Industry)			56.70	
Coal	180.00	180.00	1.45	
Coke and Coke Oven Gas			1.38	

Notes: Factors derived by NEB in consultation with Energy, Mines and Resources and Environment Canada.

(1) For detailed gasoline and diesel transportation emissions factors, see below.

Table 11-3 (Continued)
Transportation VOC Emission Factors

	Grams per Mile						
	Atlantic	Quebec	Ontario	Manitoba	Saskatchewan	Alberta	British Colunbia & Territories
			Light Duty Trucks - Mogas				
1989	3.60	3.65	3.79	4.20	4.26	3.77	3.87
1990	3.28	3.30	3.46	3.85	3.91	3.41	3.52
1995	2.37	2.37	2.51	2.80	2.85	2.45	2.54
2000	1.91	1.91	2.03	2.26	2.30	1.96	2.04
2005	1.80	1.79	1.92	2.12	2.15	1.84	1.92
2010	1.80	1.79	1.92	2.12	2.15	1.84	1.92
			Medium / Heavy Duty Trucks - Mogas				
1989	5.28	5.45	5.82	5.81	5.84	5.35	6.90
1990	4.60	4.66	5.09	5.09	5.12	4.58	5.99
1995	3.54	3.56	3.92	3.95	3.97	3.50	4.55
2000	3.26	3.29	3.60	3.65	3.67	3.22	4.15
2005	3.15	3.15	3.48	3.53	3.55	3.11	3.98
2010	3.15	3.15	3.48	3.53	3.55	3.11	3.98
			Cars - Mogas				
1989	2.52	2.59	2.96	3.73	3.87	3.18	3.43
1990	2.34	2.36	2.78	3.52	3.66	2.95	3.24
1995	1.62	1.61	1.99	2.53	2.65	2.08	2.42
2000	1.39	1.37	1.66	1.95	2.01	1.60	1.97
2005	1.35	1.33	1.59	1.78	1.83	1.47	1.84
2010	1.35	1.33	1.59	1.78	1.83	1.47	1.84
			Light Duty Trucks - DFO				
1989	0.54	0.54	0.54	0.54	0.54	0.54	0.54
1990	0.54	0.54	0.54	0.54	0.54	0.54	0.54
1995	0.45	0.45	0.45	0.45	0.45	0.45	0.45
2000	0.48	0.48	0.48	0.48	0.48	0.48	0.48
2005	0.50	0.50	0.50	0.50	0.50	0.50	0.50
2010	0.50	0.50	0.50	0.50	0.50	0.50	0.50
			Medium / Heavy Duty Trucks - DFO				
1989	2.04	2.04	2.04	2.04	2.04	2.04	2.04
1990	1.90	1.90	1.90	1.90	1.90	1.90	1.90
1995	1.63	1.63	1.63	1.63	1.63	1.63	1.63
2000	1.55	1.55	1.55	1.55	1.55	1.55	1.55
2005	1.54	1.54	1.54	1.54	1.54	1.54	1.54
2010	1.54	1.54	1.54	1.54	1.54	1.54	1.54
			Cars - DFO				
1989	0.29	0.29	0.29	0.29	0.29	0.29	0.29
1990	0.29	0.29	0.29	0.29	0.29	0.29	0.29
1995	0.29	0.29	0.29	0.29	0.29	0.29	0.29
2000	0.29	0.29	0.29	0.29	0.29	0.29	0.29
2005	0.29	0.29	0.29	0.29	0.29	0.29	0.29
2010	0.29	0.29	0.29	0.29	0.29	0.29	0.29

Note: Factors derived with assistance of Environment Canada, based on NEB projections of car and truck vintage and stock.

Table A11-4
CO2 Gas Emissions

Kilotonnes	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential										
Oil	20550	20222	20551	20102	19654	19204	18757	16984	15764	14839
Natural Gas	28942	28091	29702	29851	30016	30208	30416	31472	32100	32922
LPG	1276	1219	1264	1268	1274	1279	1284	1317	1357	1407
Wood	6996	6975	7188	7194	7203	7210	7217	7286	7375	7489
Other	211	179	177	171	165	159	153	123	102	81
Total	**57975**	**56685**	**58880**	**58586**	**58312**	**58061**	**57828**	**57182**	**56699**	**56738**
Commercial										
Oil	7849	7721	7839	7843	7807	7779	7760	7696	7599	7478
Natural Gas	18482	18209	19074	19256	19362	19528	19735	20676	21681	22676
LPG	1429	1373	1422	1428	1428	1431	1436	1455	1473	1487
Other	129	127	136	143	149	155	162	197	245	296
Total	**27889**	**27431**	**28471**	**28670**	**28745**	**28893**	**29092**	**30025**	**30998**	**31937**
Industrial										
Oil	24860	24757	24185	24785	25707	26880	27715	32763	41332	54922
Natural Gas	46771	45691	47110	48053	49984	51508	52932	57333	57710	55421
LPG	1692	1637	1645	1664	1714	1763	1801	1873	1982	2120
Coal, Coke And Coke Oven Gas	20456	19935	20514	21054	22022	23197	24014	25382	34866	43965
Hog Fuel and Pulping Liquor	40750	40759	40377	40530	40834	41237	41574	41503	41725	42298
Other	0	0	0	0	0	0	36	325	463	584
Total	**134529**	**132780**	**133831**	**136087**	**140260**	**144585**	**148072**	**159179**	**178079**	**199311**
Transportation										
Oil	132557	130282	129401	130660	131679	132685	133716	138503	142355	146669
Natural Gas	113	109	148	187	226	265	305	501	697	893
LPG	1581	1618	1654	1691	1727	1764	1800	1983	2166	2349
Total	**134251**	**132008**	**131203**	**132538**	**133633**	**134714**	**135821**	**140987**	**145217**	**149911**
Own Use and Conversions excluding Electricity Generation										
Oil	16778	16435	16225	16345	16530	16708	16751	17505	18682	20411
Natural Gas	9703	10216	10732	11297	11487	11720	11949	12570	13122	12908
LPG	385	383	392	400	407	415	421	449	481	517
Coal	16046	15736	16269	16710	17525	18547	19232	20303	21388	22560
Total	**42913**	**42770**	**43618**	**44752**	**45949**	**47389**	**48354**	**50827**	**53673**	**56396**
Electricity and Steam Generation										
Oil	12796	11487	8561	7990	8345	8296	6652	6298	7399	9712
Natural Gas	6810	4995	2505	2614	2808	3061	3328	4112	5417	5948
Coal	80976	73091	71738	71738	72212	75394	81296	93554	103694	109449
Hog Fuel and Pulping Liquor	2433	2503	3072	3301	3727	3953	4210	4535	4585	4645
Other	601	0	0	0	0	0	0	0	0	0
Total	**103616**	**92076**	**85876**	**85643**	**87092**	**90704**	**95486**	**108499**	**121095**	**129754**
Total CO2 From Primary Energy Demand										
Oil	215390	210904	206762	207725	209722	211552	211351	219749	233131	254031
Natural Gas	110821	107311	109270	111258	113882	116290	118665	126665	130727	130768
LPG	6364	6231	6377	6452	6551	6651	6743	7077	7460	7880
Coal, Coke And Coke Oven Gas	117478	108762	108521	109502	111759	117138	124542	139239	159948	175974
Renewables	50179	50237	50636	51025	51765	52400	53002	53324	53686	54432
Other	941	306	313	314	314	314	351	645	810	961
Total	**501173**	**483751**	**481879**	**486276**	**493993**	**504345**	**514654**	**546699**	**585762**	**624046**
Upstream Oil & Gas Sector	**32000**	**33800**	**35700**	**37300**	**38500**	**40300**	**41300**	**42900**	**53400**	**50700**
Total CO2 Emissions	**533173**	**517550**	**517579**	**523576**	**532491**	**544646**	**555953**	**589599**	**639161**	**674747**

Notes: 1989 is last year of actual data.
Definition of "Other" varies slightly by sector.

Table A11-5
Nitrogen Oxides (NOX) Emissions

Kilotonnes

	1989	1990	1991	1992	1993	1994	1995	2000	2005	2010
Residential	113	112	114	114	114	114	114	114	114	116
Commercial	61	60	62	62	63	63	64	67	69	72
Industrial	308	303	306	311	321	331	339	366	421	479
Transportation	937	893	850	818	781	741	698	650	658	692
Own Use and Conversions Excluding Electricity Generation	84	83	85	87	89	93	95	100	106	111
Electricity Generation	262	232	217	217	219	223	229	266	290	307
Total NOX Emissions From Primary Energy Demand	**1765**	**1683**	**1634**	**1609**	**1587**	**1565**	**1539**	**1563**	**1658**	**1777**
Upstream Oil and Gas Sector	203	212	218	224	226	235	242	251	272	273
Total NOX Emissions	**1968**	**1895**	**1852**	**1833**	**1813**	**1800**	**1781**	**1814**	**1930**	**2050**

Note: 1989 is last year of actual data.

Table A11-6
Volatile Organic Compounds (VOC) Emissions

Kilotonnes

	1989	1990	1991	1992	1993	1994	1995	2000	2001	2010
Residential	125	124	128	128	128	128	128	130	131	133
Commercial	4	4	4	4	4	4	4	4	5	5
Industrial	34	34	34	34	35	35	36	37	38	40
Transportation	676	630	604	585	563	540	515	471	479	509
Own Use and Conversions	5	4	4	4	4	5	5	5	6	6
Total VOC Emissions	**844**	**796**	**774**	**756**	**735**	**712**	**688**	**647**	**659**	**693**

Note: 1989 is last year of actual data.

National Energy Board

CANADIAN ENERGY

Supply and Demand 1990 - 2010

SUMMARY

June 1991

CANADIAN ENERGY
SUPPLY AND DEMAND 1990-2010

SUMMARY REPORT

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Table of Contents

Energy supply and demand can be measured in many different units. We convert these, for purposes of comparison, to multiples of joules. In particular, we refer to gigajoules (a thousand million joules) - about the energy contained in 30 litres of gasoline, the petajoule (a million gigajoules) - about the energy used for all purposes in Toronto or Montreal about every 17 hours, and the exajoule (a thousand petajoules). A table of key conversion factors, terms and abbreviations appears on page 20.

Foreword

The National Energy Board ("NEB" or "the Board") was created by an Act of Parliament in 1959. The Board's regulatory powers under the *National Energy Board Act* ("the Act") include the authorizing of the export of oil, gas and electricity and of the construction of interprovincial and international pipelines and international power lines, and the setting of just and reasonable tolls for pipelines under federal jurisdiction. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception, the Board has prepared and maintained projections of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. In a July, 1987 decision in which the Board adopted a Market-Based Procedure for regulating natural gas exports, the Board indicated its intention to continue to produce and publish these *Canadian Energy Supply and Demand* reports as one component of the ongoing monitoring part of the Market-Based Procedure. The latest of these reports was issued in the fall of 1988.

Since September 1988, there has been evolution in energy markets and government policies in both Canada and the United States, the major market for our exports of energy. In addition, environmental issues, which relate in large measure to the production and use of energy, have become more prominent in Canada and internationally.

In May 1990, the Board announced that its staff would update the September 1988 Report.

In conducting its analysis, Board staff made use of an informal consultation process, which it has found to be an effective way of obtaining views regarding its projections of energy supply and demand. This process also permits staff to obtain the advice of interested parties at reduced cost to them and to the Board.

Although the Board did not request formal submissions, any party interested in providing its views was invited to do so. Board staff prepared two information packages which were made available for public comment. The first, issued in May, described preliminary views on assumptions, and the second, issued in the fall, provided preliminary projections. Comments received were made publicly available in the Board's library in Ottawa and at its Calgary office. Two rounds of consultations were held. The first concerned methodology and assumptions as to, for example, world oil prices, natural gas and electricity pricing and trade, and economic growth and environmental issues; the second, preliminary projections. These consultations encompassed governments, industry, and other interested parties in both Canada and the United States.

In light of the consultations and the written comments received, Board staff developed the revised projections contained in this report, including the assumptions and analysis underlying them. We thank all those who generously gave of their time and expertise to this endeavour; their input was most useful.

These reports are issued by the Board for the information of the public. A number of parties raised concerns over the use of *Canadian Energy Supply and Demand* reports in the Board's regulatory proceedings, and questioned whether these reports are an official reflection of Board views. The Board therefore wishes to clarify its views in this regard.

The Board recognizes that parties have not had the opportunity to examine or test the findings and conclusions contained in these reports in a public forum. Material from them may be used as part of the evidentiary record in particular regulatory proceedings to the extent that any party chooses to rely on such material, just as it could rely on any public document. In such a case, the material in effect is adopted by the party introducing it. In this respect, there has been no change in the way in which the report is used by the Board.

This Summary report is a companion volume to a detailed report which provides *detailed* information on the assumptions, methodology and results of the analysis of the supply and demand for energy in Canada, and of the associated emissions of certain gases. Copies of this Summary report or the detailed report can be obtained by contacting the Board at 311-6th Ave. S.W., Calgary, Alberta T2P 3H2 (403) 292-4800.

Introduction

Since the publication of our previous report *Canadian Energy Supply and Demand 1987 - 2005* (the September 1988 Report), world oil prices have traded in a narrow range of $16 to $20 (in US dollars of 1990) except for the volatility caused by the Gulf war, North American natural gas trade has grown, there has been concern about the long-term adequacy and sources of electricity supply in the U.S., and public concern has increased about protection of the environment.

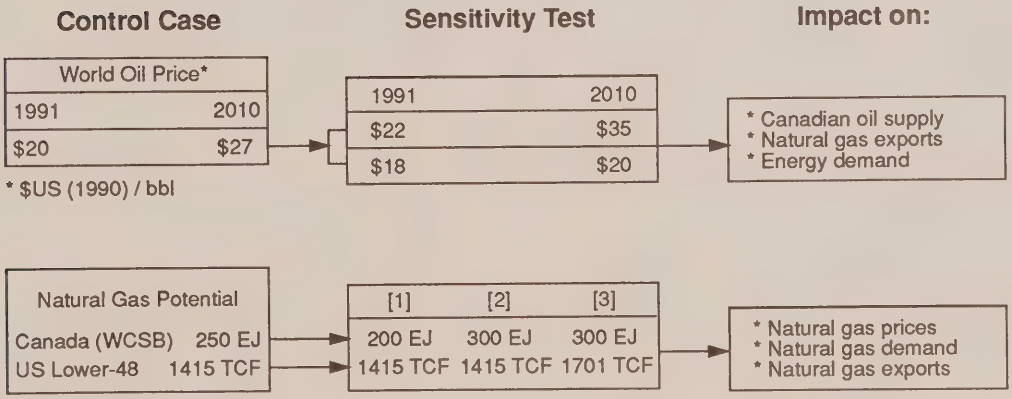
Our general approach is somewhat different from that of the September 1988 Report. In that report we presented two cases based on higher and lower sustainable paths of world oil prices. For this report we prepared a single projection (termed the "Control Case") of Canadian energy supply and demand based on one set of world oil price and economic growth projections, and then subjected it to various sensitivity tests to reflect uncertainties in factors having an important influence on the projections. We do not view the Control Case as a most likely projection, but rather as a centre-point for the sensitivity tests. The sensitivity tests include examining the impacts of higher and lower world oil prices, Canadian natural gas resources, and North American natural gas resources.

Other major innovations in this report include:

- more detailed analysis of the North American natural gas market; and
- the inclusion for the first time in these reports of estimates of emissions of gases from the production and use of energy, including those gases linked to the greenhouse effect, acid rain, and low-level ozone.

Canada's energy future will be determined by a combination of domestic and international factors influencing the rate and character of economic growth, energy price development and the ways in which we produce and consume energy. We have cast our analysis in the context of the existing framework of institutional practices and public policies, the most important feature of which is that market forces will largely determine energy prices, supplies and demands. We have assumed that this framework will continue over the study period.

Figure 1
Scope of Analysis



Canadian Economic Growth

In the Control Case, we assume long-term economic growth of about 2.3 percent per year. The economy could perform above or below this estimate, which would cause our energy demand projections to vary accordingly as noted below.

Since energy is used in the production of goods and services, it follows that, other things being equal, the higher the rate of economic growth, the higher will be the demand for energy in Canada. However, the structure of economic activity also has an important influence on the level and fuel mix of Canadian energy demand. For example, some industries use energy in their production processes much more intensively than others. In our Control Case, growth is somewhat more concentrated in the goods producing sectors, than in services; in this case Canada continues to rely on its resource base and its manufacturing sector as sources of growth. Such a pattern of growth emphasizes those industries where Canada has historically had a comparative advantage in international markets, and is consistent with the thrust of the Free Trade Agreement and the Goods and Services Tax, both of which are acknowledged to favour goods over service production. However, the energy-intensive industries share of total economic output is expected to decline from over 10.5 percent in 1989 to less than 10 percent by the year 2010.

Table 1

Canadian Economic Activity
Average Annual Growth Rates (percent)

	1989 - 2010
Real Gross Domestic Product	2.3
Real Personal Disposable Income	1.9
Households	1.4
Car Stock	1.5

Table 2

Output by Sector

Average Annual Growth Rates (Percent)

	1989-95	1995-00	2000-05	2005-10	1989-10
Industrial Sector	2.5	2.5	2.7	2.9	2.6
Forestry	1.5	0.9	0.8	1.0	1.1
Mining	2.3	1.3	1.7	0.5	1.5
Manufacturing	2.8	2.7	2.9	3.5	3.0
Construction	2.0	2.8	2.7	2.8	2.5
Energy - intensive[a]	2.4	1.7	1.8	1.3	1.8
Commercial Sector	1.9	2.1	2.1	2.0	2.0
Total Gross Domestic Product	**2.2**	**2.2**	**2.3**	**2.3**	**2.2**

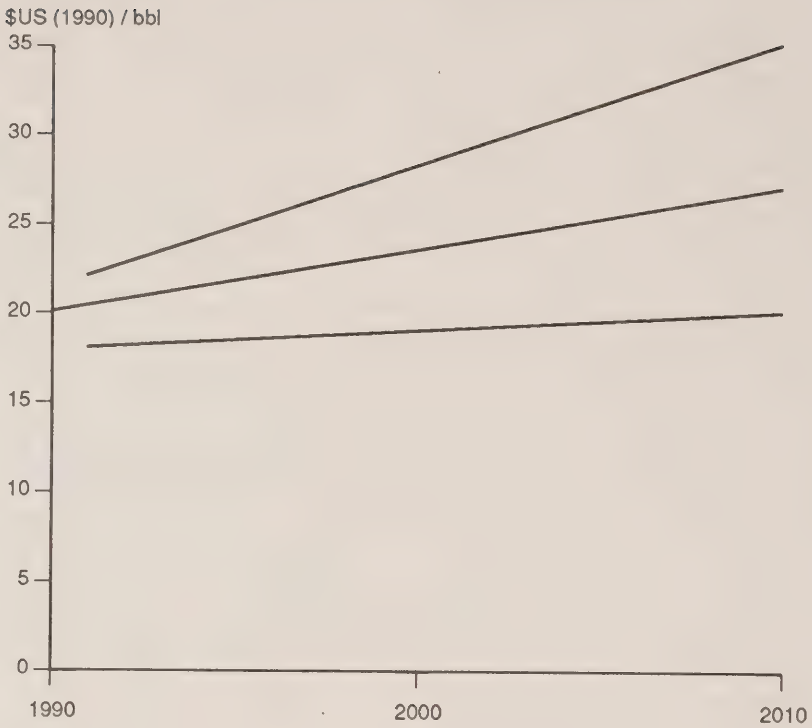
Notes: Real Gross Domestic Product at factor cost, (1981 Dollars).

[a] Mining, smelting and refining, iron and steel, pulp and paper, chemicals, cement and petroleum refining.

Energy Pricing

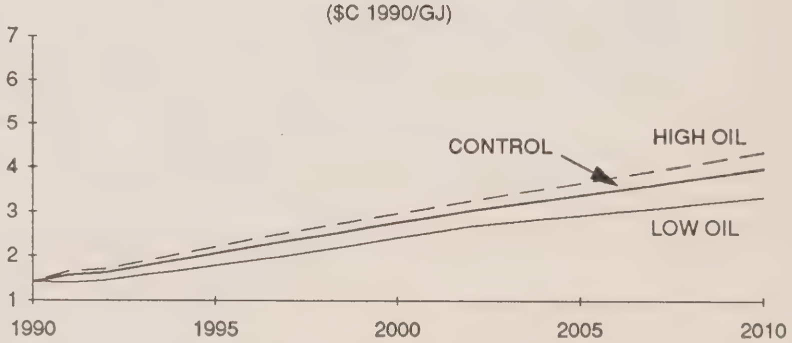
Energy pricing is fundamental to any supply and demand outlook, and **oil prices** have an important influence on energy pricing in general. We project a sustainable range of oil prices over the longer term, although we recognize that prices may temporarily fall outside the range. Our outlook is for sustainable oil prices ranging from $18 to $22 per barrel in 1991, with the range growing to $20 to $35 in 2010 (all in 1990 U.S. dollars). This range reflects both political and economic uncertainties associated with projecting long-term oil prices. For analytical purposes, we have presented a Control Case roughly in the middle of the range, growing from $20 in 1991 to $27 by 2010.

Figure 2
NEB World Oil Price Projections



Natural gas pricing is determined in the North American market, and our assessment of future prices is influenced by assumptions about the size and costs of natural gas resources and the growth in natural gas demand. A plausible range of natural gas prices results from our various scenarios, but we do project substantial real growth in natural gas prices over the study period. Our Control Case Alberta natural gas fieldgate price increases from $1.40 per gigajoule in 1992 to $4.20 in 2012, and our sensitivity cases produce a range of $3.50 to $4.65 by 2012 (all in 1990 Canadian dollars).

Figure 3
Natural Gas Price Projection
Alberta Fieldgate
($C 1990/GJ)



We have attempted to reflect a measure of technological improvement in our analysis but recognize that some will suggest that we have not yet adequately accounted for the extent to which advances in technology may mitigate increases in costs and thereby prices over the longer term. We also anticipate that the ongoing supply surplus in Western Canada will continue to place downward pressure on natural gas prices in the short term, perhaps to a greater extent than accounted for in our results. However, our projection of both world crude oil prices and of North American natural gas prices over the longer term tend to be at the lower end of the range of published projections.

Electricity prices are not market determined, but are largely regulated on a cost-of-service basis. In the short term our price outlook is guided by the announced intentions of the utilities. Based on our consultations with utilities, we think it reasonable to assume that over the long term additional supply can generally be produced at a rolled-in cost which will remain stable in real terms.

Table 3

Average Annual Growth In Current Dollar Electricity Prices

(percent)

	1990-93			1993-2010
	Residential	**Commercial**	**Industrial**	**All Sectors**
Atlantic	7.0	6.9	7.1	4.6
Quebec	8.1	11.9	8.5	4.6
Ontario	10.2	12.9	11.8	4.9
Manitoba	6.8	5.9	6.0	3.6
Saskatchewan	5.1	4.9	4.9	4.6
Alberta	9.0	8.5	8.5	4.6
British Columbia	3.7	3.2	3.2	4.6

Energy Demand

Our expectations are for low energy demand growth for Canada, with end use demand growing from 7600 petajoules in 1989 to 9800 petajoules in 2010 in the Control Case, an increase averaging 1.2 percent per year. These projections are predicated on modest economic growth, ongoing energy efficiency improvements associated with technological change, environment-related measures considered viable given our price outlook, and demand management programs.

We recognize that demand could be somewhat greater than we have projected, for example if economic growth were greater or efficiency gains less than in our analysis. Energy demand growth could also be less than in our Control Case, for example due to more aggressive environmental protection or economic growth lower than we have assumed, especially if growth were more heavily weighted toward less energy-intensive activity. It is plausible that demand may be from 10 percent below our Control Case to 15 percent above by 2010.

End use fuel shares are expected to change very moderately over the projection period. Although the gas share increases slightly in the period to 2000, by 2010 the shares of electricity (22 percent) and coal (6 percent) are each about 2 percentage points higher than in 1990, and those of oil (37 percent) and gas (25 percent) are lower than in 1990.

Figure 4

End Use Energy Demand by Fuel Canada

(Petajoules)

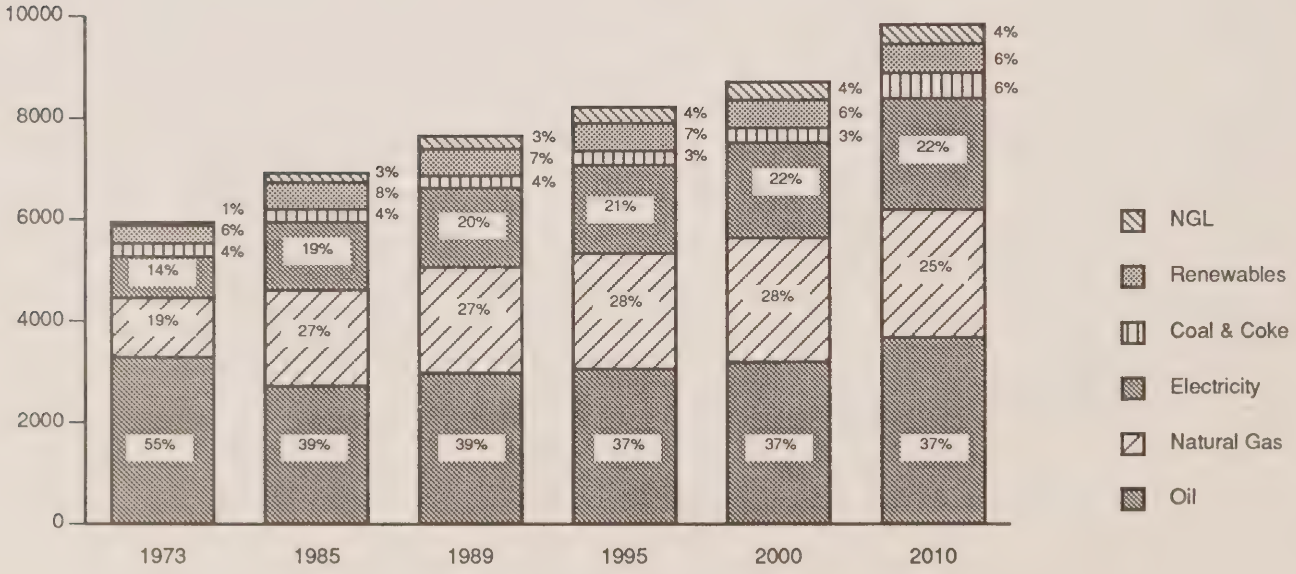


Figure 5

Range of End Use Energy Demand

(Petajoules)

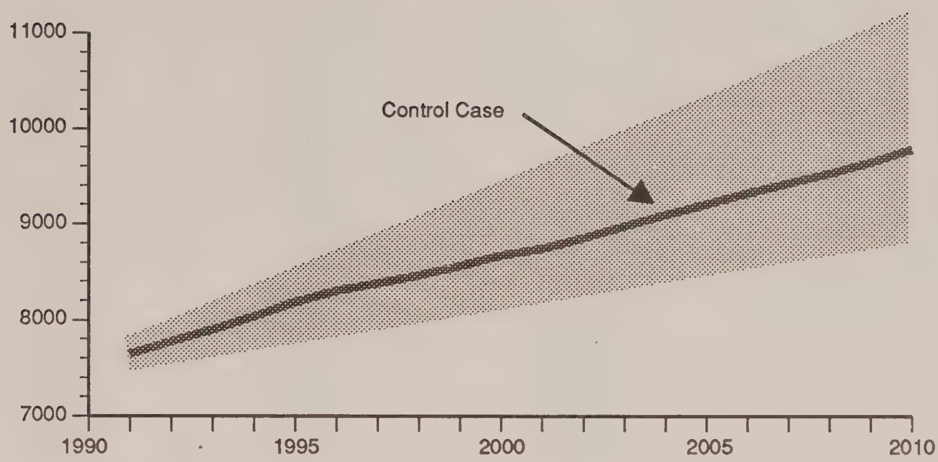
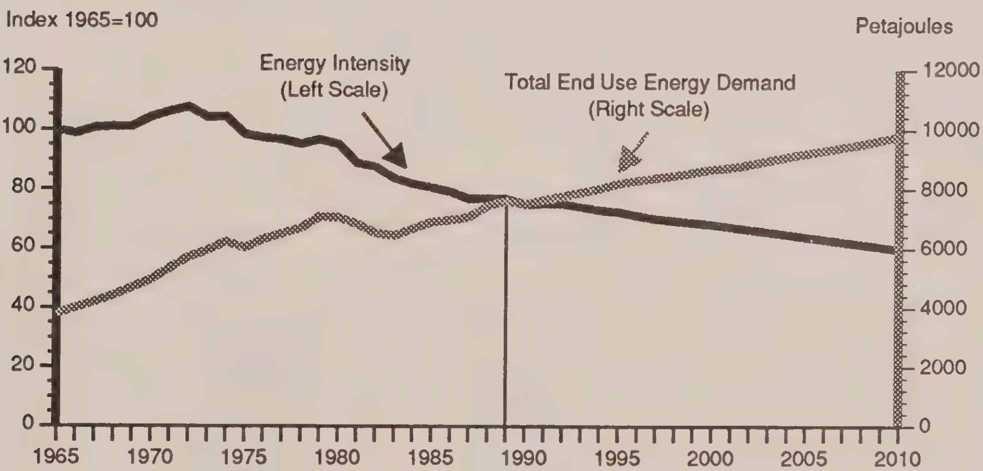


Figure 6

Energy Intensity and End Use Energy Demand



Note: End use energy demand is in petajoules;
Energy intensity is end use energy demand per unit of 1981$real GDP, indexed to 1965.

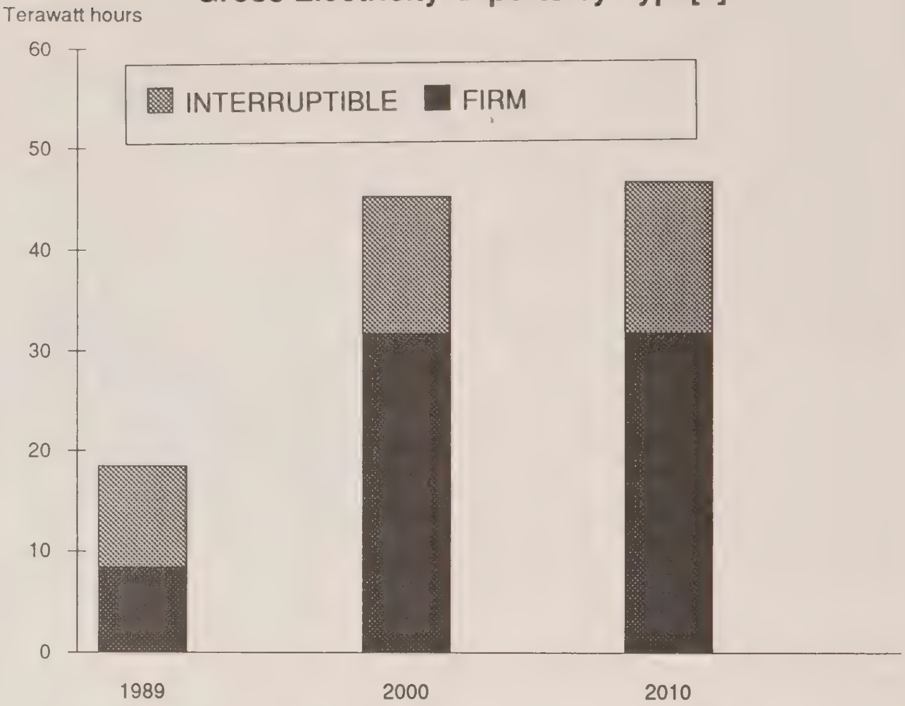
Energy Supply and International Trade

Our price projections, demand profiles and assumptions regarding the size and cost of the resource have interesting implications for energy supply and international trade.

Our projections of the expansion of **electricity** generating capacity are driven by our analysis of the prospects for electricity demand growth, given our outlook on the rate and characteristics of economic growth, on electricity prices, on the penetration of new technologies, and on the effect of demand management programs and incentive pricing arrangements. We conclude that, on average over the study period, the rate of growth in electrical energy demand will be at a rather modest 1.5 percent per year.

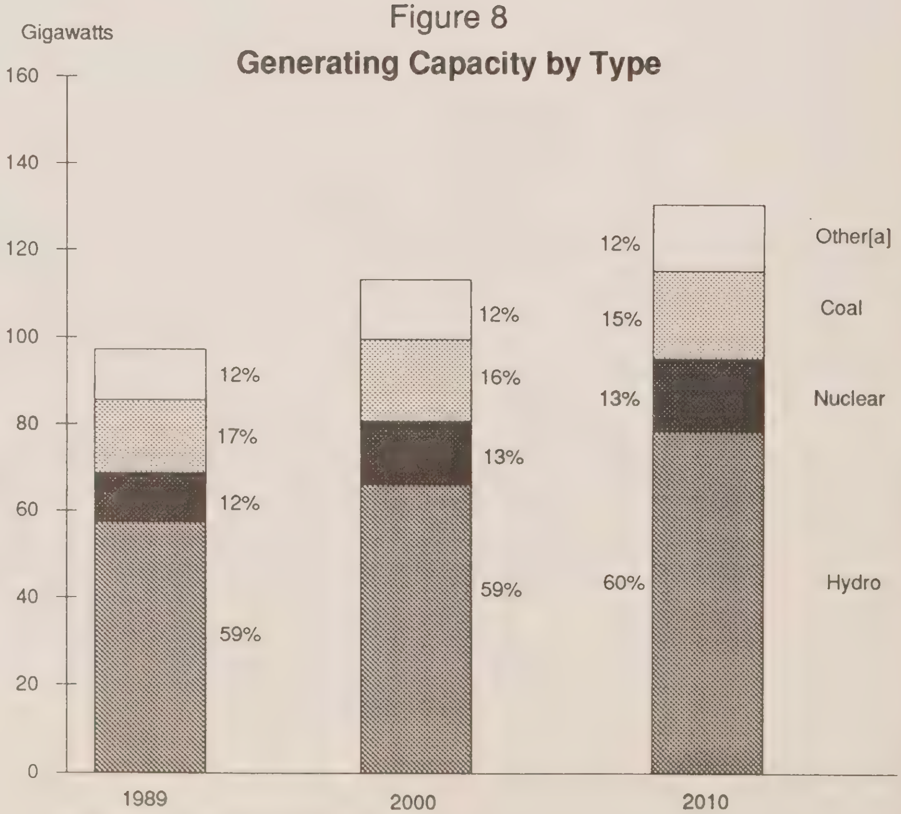
Based on commitments already made, and on our assessment of utility plans and of U.S. markets, we see firm exports of electricity rising from the 1990 level of 18 terawatt hours to about 47 terawatt hours in 2010. Over the past several years, Canada's net electricity exports have fallen from the levels achieved in the mid-1980s because of Quebec's low water levels and nuclear reactor shutdowns in Ontario. Our analysis suggests that the pattern of interruptible trade will revert to the pattern of the mid-1980s, as increasing generating capacity and a return to more normal levels of precipitation result in a decline of imports to Canada and an increase in interruptible exports. Over the long run, export trade is likely to consist increasingly of firm exports.

Figure 7
Gross Electricity Exports by Type[a]



[a] Excludes exchanges

Figure 8
Generating Capacity by Type



[a] Includes mainly oil and natural gas.

Our review leads us to conclude that, notwithstanding our projection of relatively low load growth rates and growth in generation alternatives such as natural gas turbines and despite demand management programs, we will need to rely on substantial expansion of conventional sources of supply such as hydro, coal and nuclear capacity to meet the bulk of Canadian electricity demand over the study period. Some provincial utilities expect higher load growth rates than in our projections, and have committed to expansion plans accordingly.

We observe growing interest in mutually beneficial interprovincial electricity trade. This potential, combined with the possible contribution of independent power producers, widens the range of supply options which utilities can pursue.

On the electricity supply side, identification of needed capacity resources for only five to six years into the future has become a more common practice because of the major uncertainties associated with the commitment of facilities requiring long lead times. This has two kinds of risks: first that utilities will not achieve the lowest long-run incremental cost of generation, and second that additional capacity may not be available when needed to maintain adequate reserve margins.

The generation plans of several provinces have undergone or are now undergoing environmental scrutiny including public hearings held by provincial agencies. In other instances, the process of environmental review remains to be finalized. Environmental considerations associated with new electricity supplies (including a range of socio-economic factors as well as any physical impacts of development on the environment) can have an important impact not only on the timing of these developments but indeed on whether they will be developed at all.

Table 4

Generating Capacity by Region

Megawatts

	1989	**Increase 1989-2010**
Atlantic	12659	4871
Québec	28254	13473
Ontario	29327	9799
Prairies	14032	5116
B.C. and Terr.	12949	2176
Canada	**97221**	**35435**

For **natural gas** we project substantial growth in demand, especially in the U.S. electrical generation market, until around 2000. From 2000 to 2010 natural gas demand growth moderates in the Control Case because natural gas prices exceed heavy fuel oil prices, causing substitution of heavy fuel oil for natural gas. Canadian natural gas demand in the Control Case increases from 2.6 EJ in 1989 to 3.2 EJ in 2010, an average annual increase of 1 percent. Taking into account comparative gas supply and transportation costs between Canada and the U.S. and the growing size of the U.S. market, natural gas net exports grow from 1.4 EJ in 1989 to a peak of 2.4 EJ in 2007, and then recede to about 2.2 EJ by 2010 as supply from Western Canada begins to decline and frontier supply sources become competitive. Mackenzie Delta production in the Control Case commences in 2004 and Alaskan supply to the Lower-48 states commences very late in the study period. Imports to Ontario grow from about 25 petajoules in 1991 to almost 0.3 EJ in 2010. Total Canadian production is projected to increase from 4.0 EJ in 1989 to 5.6 EJ in 2007, and to moderate to 5.4 EJ in 2010.

As productive capacity from established reserves declines over the projection period, it will increasingly become necessary to rely on productive capacity from reserves additions in the WCSB, along with productive capacity from the frontier regions, to meet the increasing levels of domestic and export demand. A total of 72 exajoules of natural gas from the WCSB, or an average of 3.4 exajoules per year, is projected to be added over the

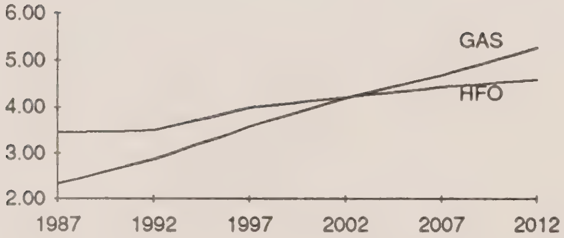
Figure 9

Control Case

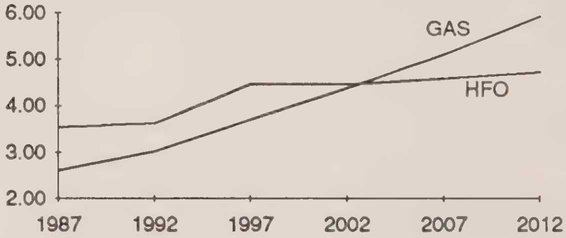
Noncore Gas and HFO Prices

($C 1990/GJ)

Canada



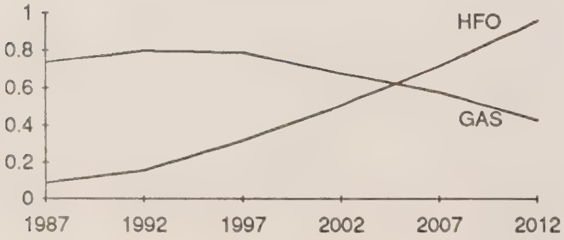
United States



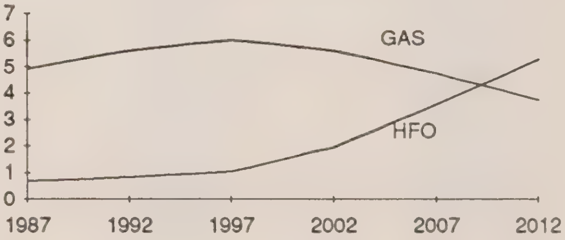
Noncore Gas and HFO Demand

(Tcf/Year)

Canada



United States



Note: Prices are at the point of end-use

period 1990 to 2010 in the Control Case

These supply, demand, trade, and price results are sensitive to assumptions about uncertain variables, especially oil prices and natural gas resource and supply costs. Low oil prices cause natural gas prices to be lower than in the Control Case. Therefore, in the low oil price case natural gas loses market share to oil earlier in time than in the Control Case and Canadian exports are lower. Higher oil prices allow higher natural gas prices, increased gas consumption and higher Canadian exports relative to those in the Control Case. With regard to Northern projects, low oil prices cause Mackenzie Delta gas to be delayed to about 2010 and Alaska gas to beyond 2010, while high oil prices allow the development of Mackenzie Delta gas around 2002 and Alaska gas somewhat earlier than in the Control Case. Canada's export potential and overall natural gas production is most sensitive to what one assumes about the size and associated costs of the Canadian natural gas resource relative to that of the U.S. The impacts of a range of estimates of recoverable resources and related supply costs for Canada and the U.S. were assessed in sensitivity cases. By 2012, our results indicate that net Canadian exports could be as low as some 1.3 EJ per year or as high as about 4 EJ per year with low and high estimates of the WCSB natural gas resource, respectively. The analytical framework we are using is such that markets are presumed to adjust smoothly to whatever assumptions are used about the resource and oil prices. Of course, prices can fluctuate substantially over time as markets adjust to changing circumstances.

Figure 10
Natural Gas Supply and Demand

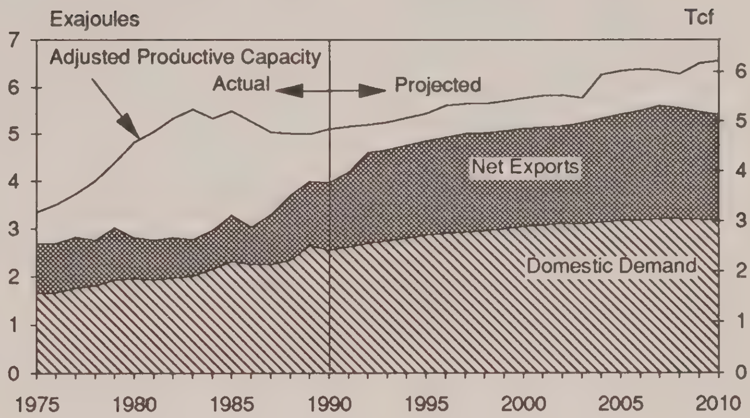
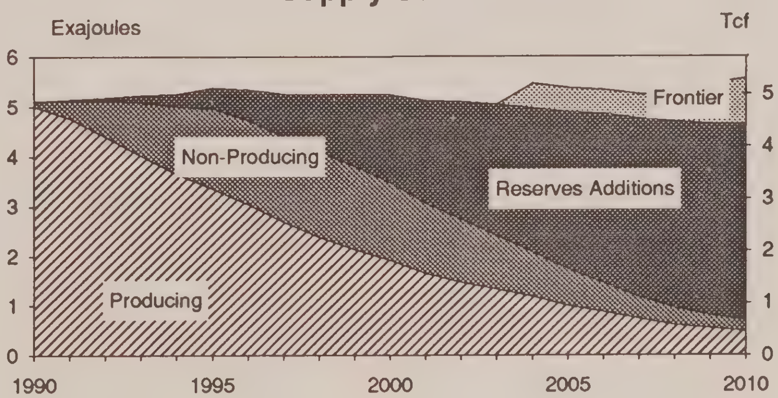


Figure 11
Productive Capacity of Natural Gas by Supply Source



Our results indicate lower natural gas prices, a larger gas market and higher net exports than shown in the 1988 Report. There are several reasons for this. Between 1988 and now, the long-term demand outlook for the U.S. market has increased because of environmental considerations, increased expected reliance on natural gas for electricity generation and increased optimism about indigenous gas supply. We have used a more generous estimate of U.S. resource potential and have reduced U.S. supply costs somewhat relative to those used in the 1988 Report. For Canada, we have used a higher estimate of resource potential in the WCSB in the Control Case and reduced our estimates of input costs, such as for drilling, both of which have the effect of reducing supply costs and lowering prices as compared to the 1988 Report. We have also attempted to reflect a more competitive energy market environment in our natural gas transportation and distribution charges, which generally has the effect of reducing these costs relative to those in the 1988 Report.

Our results suggest the importance of caution in gauging the future development of the natural gas market. There are large uncertainties about factors which can have important impacts on results, and the analytical framework itself has limitations in portraying how the market functions or reacts to changed circumstances. Our main purpose in conveying these results is to indicate broad, plausible directions of change, to the extent our information and methods allow, and to illustrate the sensitivity of results to alternative assumptions about key uncertain factors.

Figure 12
Net Canadian Exports
Range of Results
(Exajoules/Year)

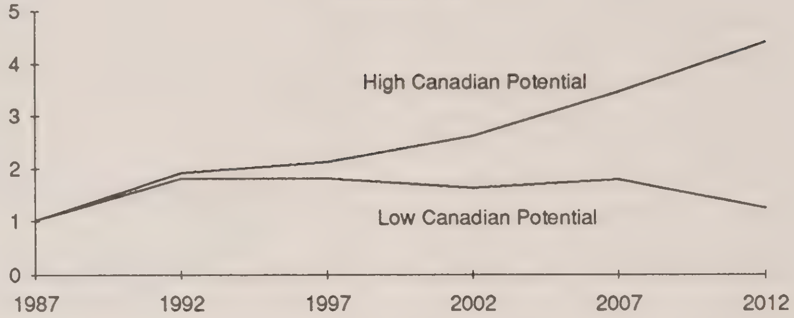
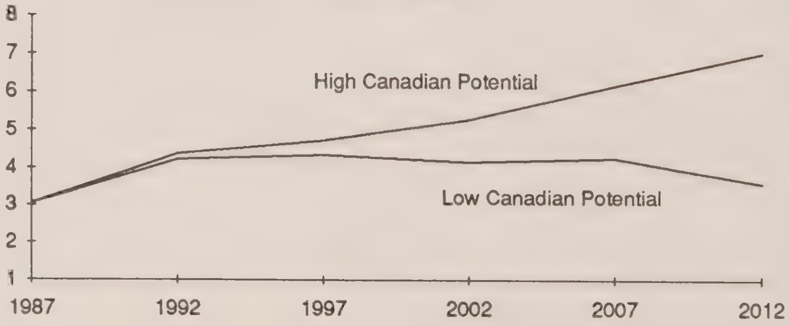


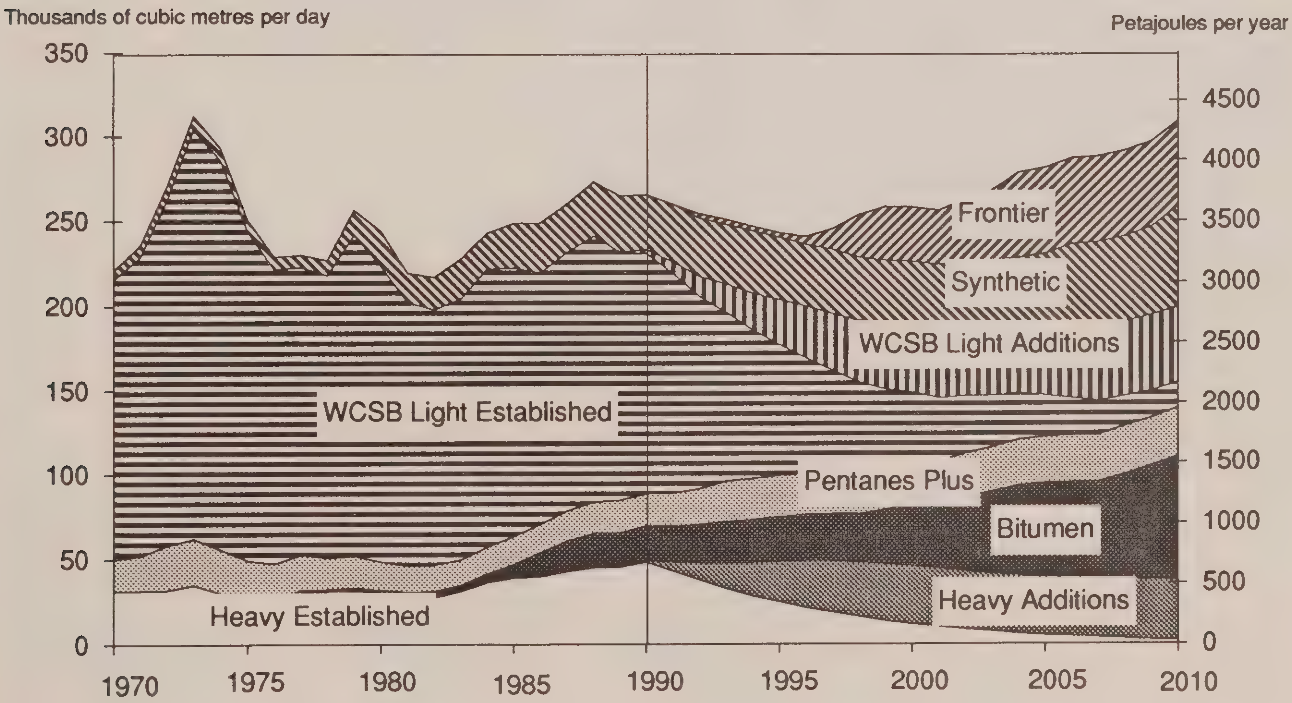
Figure 13
Canadian Natural Gas Production
Range of Results
(Exajoules/Year)



We have focussed our **oil** supply analysis on the Control Case crude oil price path and conducted high oil price and low oil price sensitivity tests to assess the impact of alternative crude oil price projections on our supply outlook. In addition to crude oil price, there are a number of other uncertain parameters, including the size of the resource and the pace of technological change, which could substantially influence the outlook for crude oil supply. Overall, our Control Case outlook suggests that Canada's crude oil and equivalent supply will remain relatively stable over the projection period, declining initially and then increasing to a level 16 percent higher in 2010 than in 1990. While the total supply of crude oil and equivalent is projected to change only modestly, the average quality of the crude oil and the regional distribution of supply changes considerably. Over the projection period heavy crude oil comprises an increasing proportion of the total supply and the importance of frontier supply increases, whereas supply of light crude oil from Western Canada becomes relatively less significant. Our oil price sensitivity tests indicate that the outlook for frontier, synthetic crude oil, and bitumen supply is particularly sensitive to the crude oil price projection. Many new Canadian supply sources are relatively high cost by world standards and will require real growth in prices or technological changes which reduce costs in order to become viable over the projection period.

Our Control Case crude oil and equivalent supply projection is very similar to the low case of our 1988 Report during the early portion of the projection period, but thereafter moves gradually toward the high case of that report. As in the 1988 Report, the contribution of heavy crude oil supply, particularly bitumen, and frontier supply increases and conventional light crude oil supply from the Western Canada Sedimentary Basin declines over the projection period. This has certain implications for the crude oil transportation system and refinery configuration in Canada.

Figure 14
Total Supply of Crude Oil and Equivalent



Light crude oil shipments from Western Canada to Montreal via the Sarnia-Montreal segment of the Interprovincial Pipe Line system have recently ceased. As light crude oil supply from the Western Canada Sedimentary Basin continues to decline, it will be necessary for Ontario refiners to examine their supply options, one of which would be to reverse the Sarnia-Montreal line to allow imported light crude oil to be shipped to Sarnia via Portland, Maine. We anticipate that over most of the projection period the growth in domestic demand for petroleum products can be met by increased utilization of existing domestic refinery capacity, together with some modest debottlenecking of refineries in conjunction with investments which will be necessary to meet more stringent environmental standards.

In our Control Case projection supply exceeds domestic crude oil demand throughout the projection period and Canada therefore remains a net exporter of crude oil and equivalent. We anticipate, however, increasing volumes of light crude oil imports to satisfy refinery feedstock requirements in the Maritimes, Quebec and Ontario and exports, primarily to the U.S., of large volumes of heavy crude oil produced in Western Canada and light crude oil produced from the East Coast offshore.

Figure 15

Remaining Reserves and Reserves Additions

(millions of cubic metres)

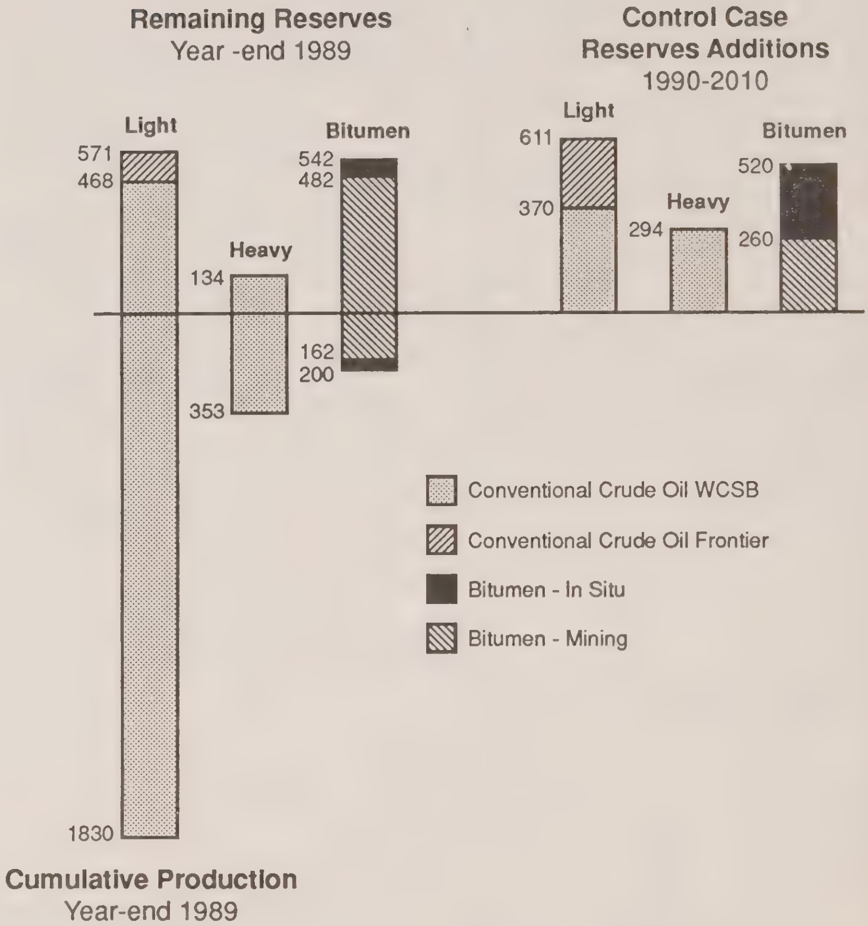


Figure 16

Composition and Source Locations of Total Crude Oil and Equivalent Supply

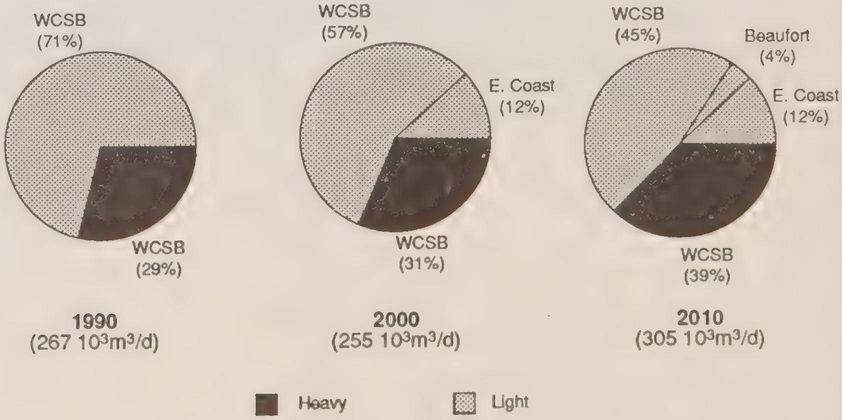
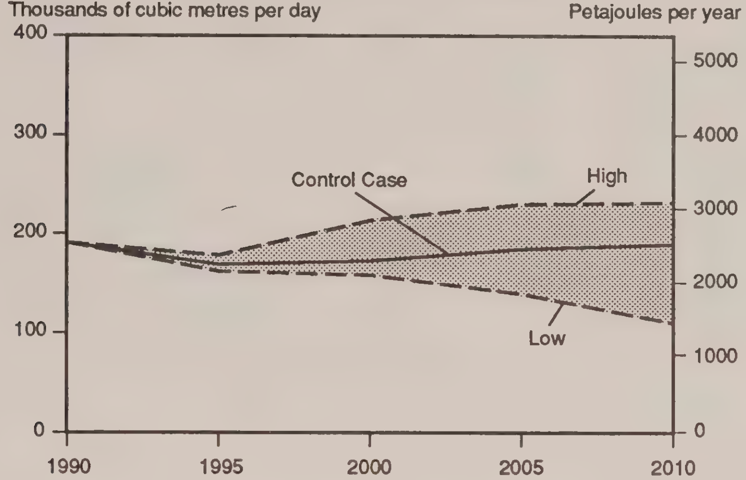


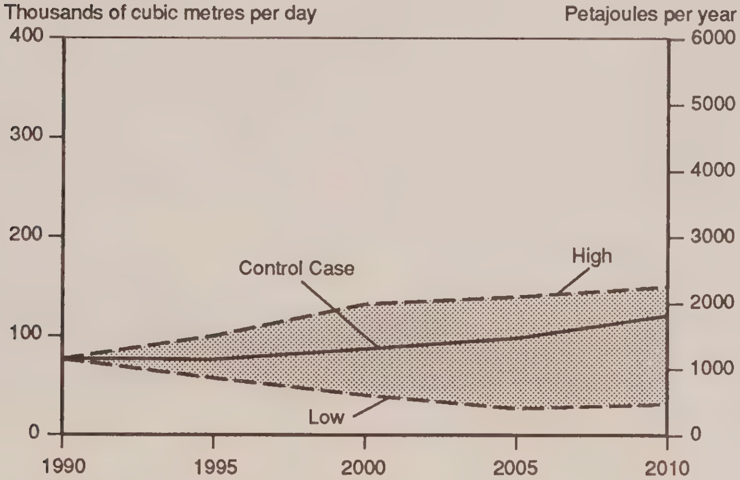
Figure 17

Productive Capacity of Crude Oil and Equivalent - Total Canada
Price Sensitivities around Control Case

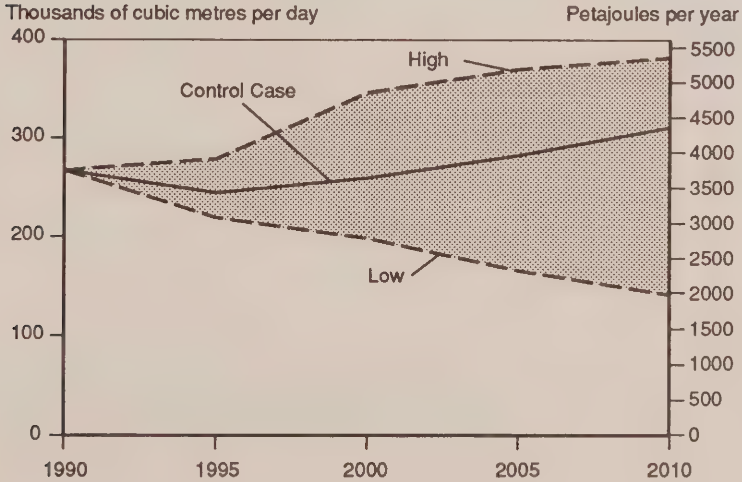
Light Crude Oil and Equivalent



Total Heavy Crude Oil



Total Crude Oil and Equivalent



Domestic demand for **natural gas liquids** is expected to increase despite reductions in the demand for NGL for use in miscible flood projects. Domestic demand for ethane is projected to increase as a result of the construction of a new ethylene plant. Propane demand is projected to rise in all sectors, with the most significant increases being in the transportation and petrochemical sectors. Completion of an MTBE plant currently under construction leads to an increase in butanes demand.

We anticipate that liquids yields will remain relatively constant but this depends upon a number of factors, including the composition of future natural gas discoveries; as a result there is uncertainty in this projection. NGL supply potential is expected to increase over the period as natural gas production increases in response to rising domestic and export demand. Overall, our projections of NGL supply are up significantly from the high case projections in our 1988 Report because of higher projections of natural gas production and of liquids yields. To the extent that natural gas production were higher or lower than projected in the Control Case, there would be a commensurate increase or decrease in the potential NGL supply. Our analysis indicates that for each of ethane, propane and butanes there will be a substantial excess of potential supply over domestic demand during the projection period.

Figure 18
Ethane Supply and Demand
Control Case

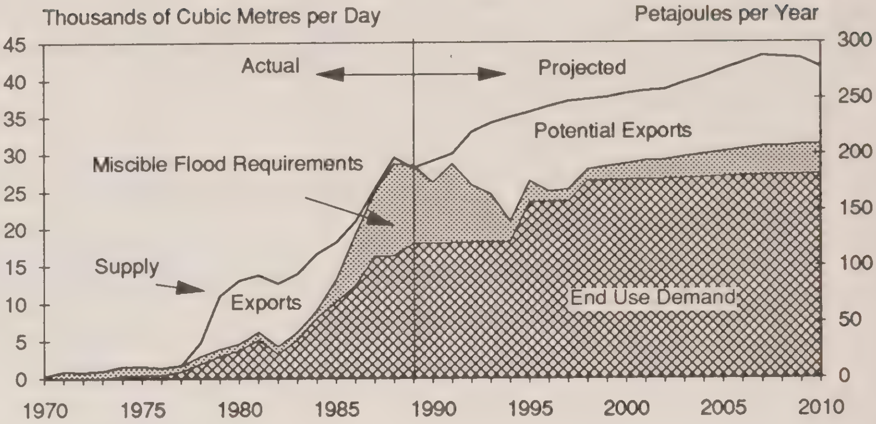


Figure 19
Propane Supply and Demand
Control Case

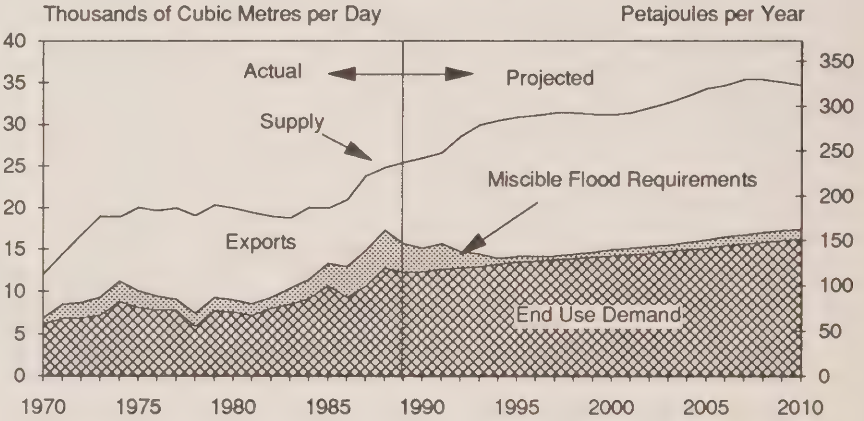
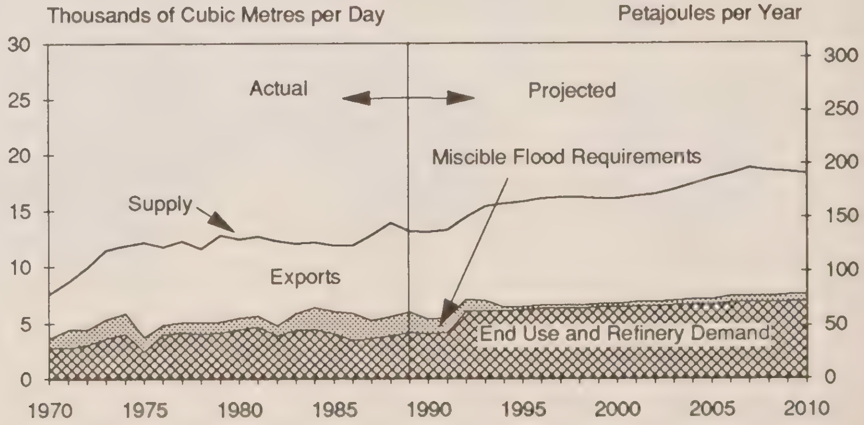


Figure 20
Butanes Supply and Demand
Control Case

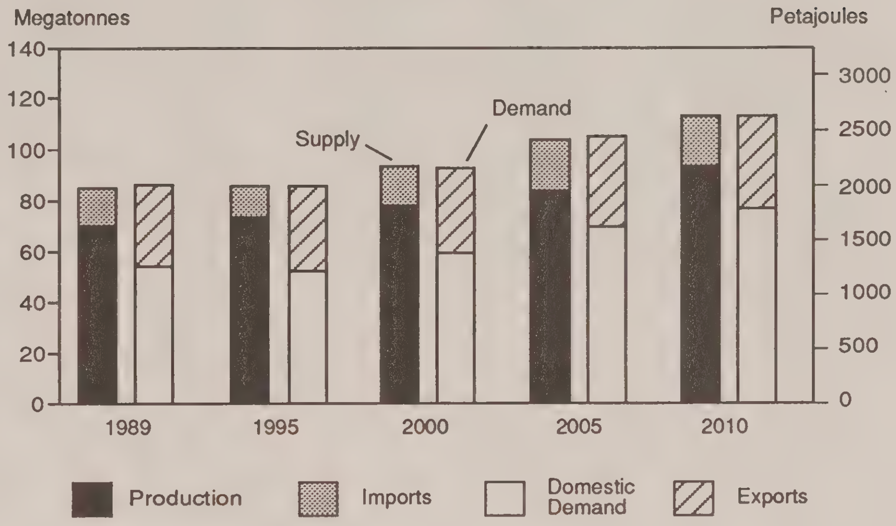


Our projections in the Control Case show considerable growth in domestic demand for **coal** over the study period. In Ontario and Quebec markets, domestic supply continues to face stiff competition from U.S. coals, and Canadian producers are not expected to increase their market shares. Growth in electricity generation markets in the West and in the Atlantic region are projected to result in increased demand for Canadian coals.

With regard to world coal trade we see continued growth, particularly for thermal coals. Canada is at a competitive disadvantage in some markets, mainly because of high transportation costs incurred in moving coals long distances by rail to tidewater and the emergence of new low cost suppliers on the world scene. We think it reasonable to expect that we will be able to expand our exports of thermal coal, but that overall we will lose market share. Expansion of thermal coal exports may depend on the extent to which buyers wish to maintain diverse supply sources. With regard to metallurgical coal exports we have assumed that we will be able to maintain our existing level of exports.

Figure 21

Coal Supply and Demand in Canada Control Case



Gaseous Emissions

Based on our domestic energy supply and consumption outlook we have developed projections of gaseous emissions. We have made allowance in our projections for environmental policies in place as of the end of 1990 and for ongoing improvement in energy efficiency. Notwithstanding this, emissions of **carbon dioxide** are projected to increase from 533 000 kilotonnes in 1989 to 675 000 kilotonnes by 2010, an annual average increase of 1.1 percent. **Nitrogen oxides** emissions also increase, from 1970 kilotonnes in 1989 to 2050 kilotonnes by 2010, an annual average increase of 0.2 percent. However, emissions of **volatile organic compounds** decline from 840 kilotonnes in 1989 to 690 kilotonnes by 2010, an annual average decrease of 0.9 percent. **Sulphur dioxide** emissions also decline, from 1355 kilotonnes in 1989 to 1140 kilotonnes by 2010, an annual average decrease of 0.8 percent.

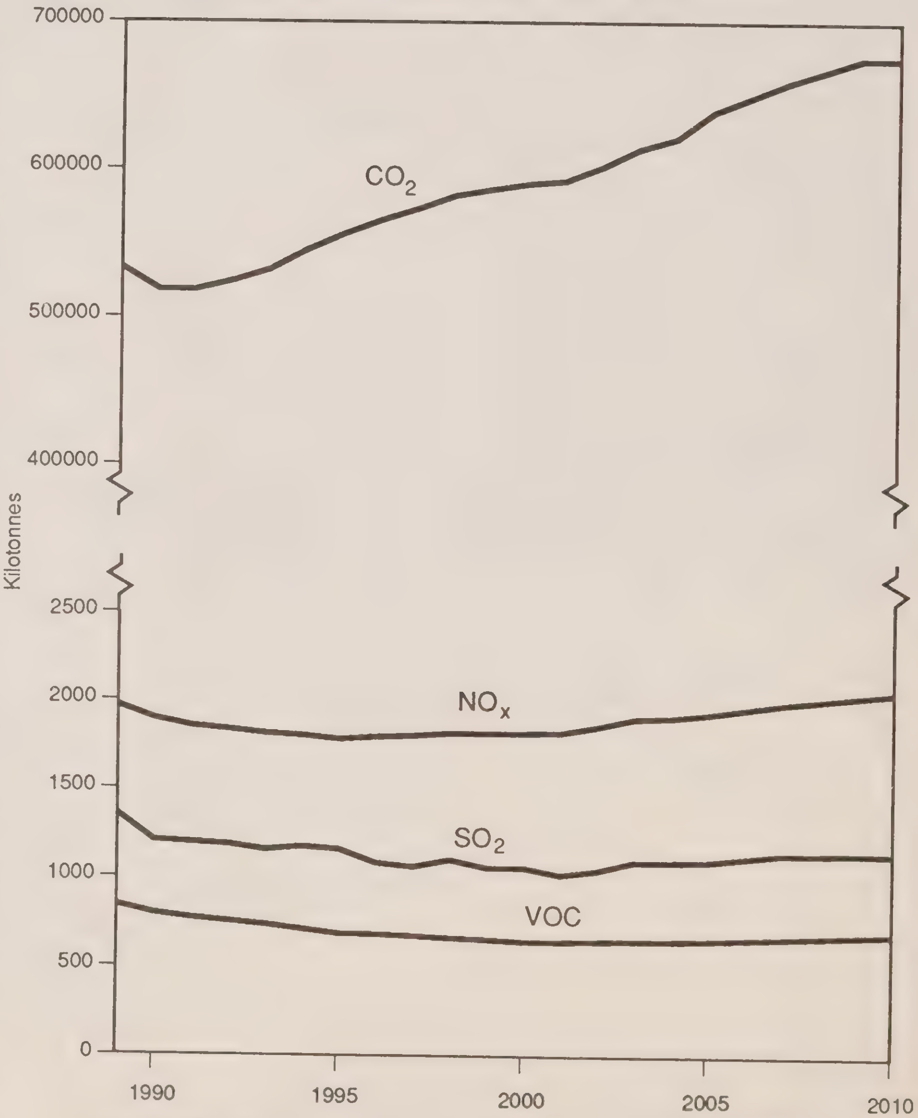
These projected emissions include only energy-related emissions; they do not encompass all energy-related emissions. The emissions projected are subject to uncertainty related both to the projected levels of energy supply and demand and to the emissions factors used.

These emissions could be further mitigated by introducing new consumption and production technologies which have not been included in the Control Case because they are generally not yet commercially viable. Over a time horizon as long as 20 years, a portion of this potential for further emissions reductions could be realized through innovations in technology and in manufacturing processes which lead to the economic viability of certain emissions reduction measures or by the introduction of specific policy measures. We have described many of the available emissions reduction measures and provided an indication as to their possible impact on gaseous emissions.

While we have endeavoured to take environmental concerns into account in the analytical work conducted for this report, the nature of this issue is such that there could be significant changes in our economic structure over the period of this study which extend well beyond the analysis we have presented.

Figure 22

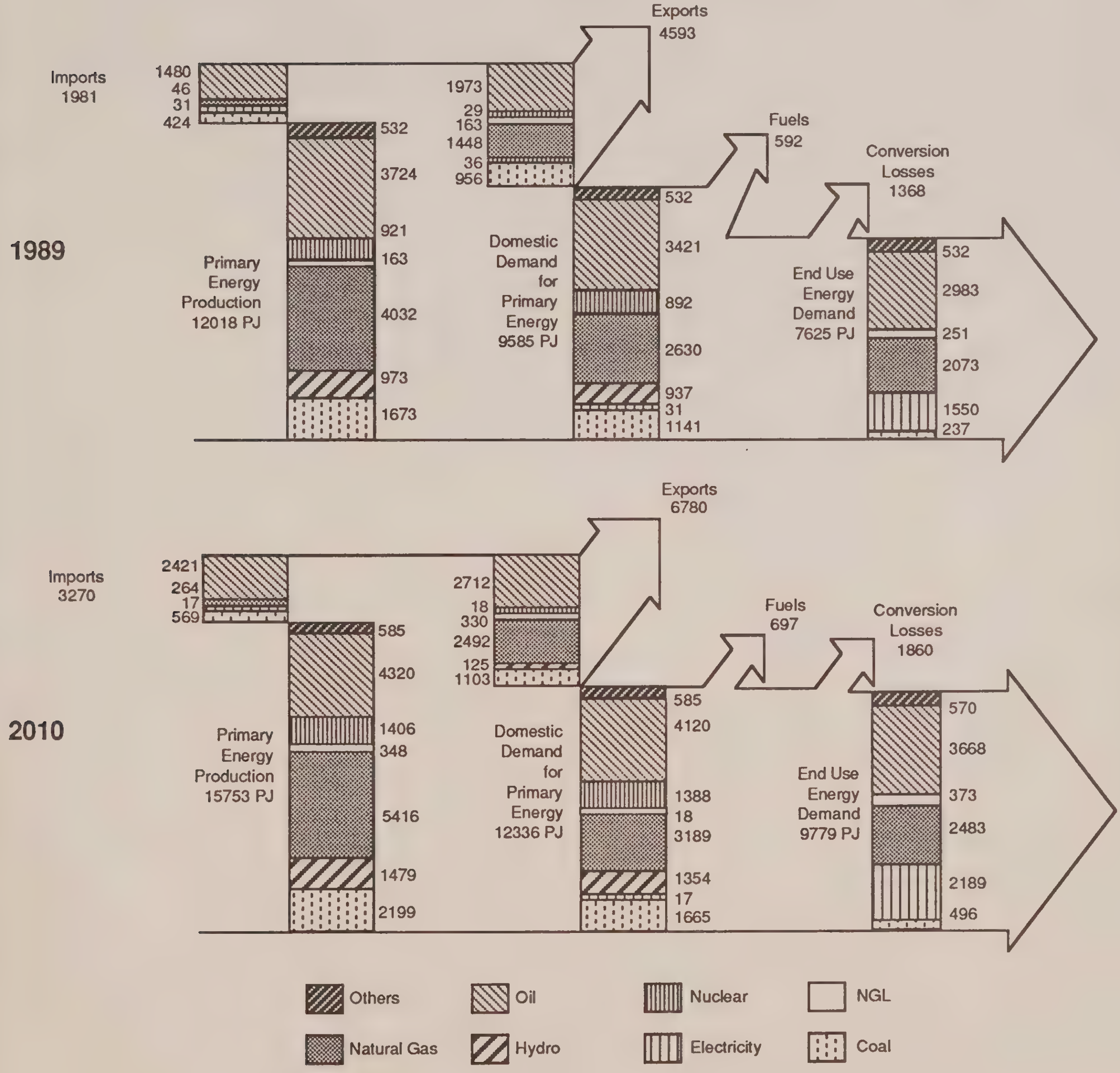
Projected Gaseous Emissions in Canada*



*Each of these lines has been drawn independently; i.e., they have not been "stacked". For example, in 1989 VOC emissions are 844 kilotonnes and SO_2 emissions are 1355 kilotonnes.

Finally, *we emphasize that there is considerable uncertainty inherent in any long-term projection of energy supply and demand and that we do not view our Control Case as a most likely projection. It is a projection around which we have conducted certain sensitivity tests for key variables having a credible range of values. Our main interest in the sensitivity tests is to illustrate a plausible range of results and to better understand the forces which determine the range. Users of our results can select the area of the projection they prefer based on their views of the range of assumptions we have tested.*

Figure 23
Energy Flows
(Petajoules)



Note: Hydro electricity converted to PJ using 3.6PJ/TW.h. and nuclear electricity converted to PJ using 12.1 PJ/TW.h.

Abbreviations of Names, Terms and Units

"NEB" or "the Board"	National Energy Board
Act	The National Energy Board Act
September 1988 Report	*Canadian Energy Supply and Demand 1987-2005* Summary and detailed reports, NEB, September, 1988
October 1986 Report	*Canadian Energy Supply and Demand 1985-2005* Summary and Detailed Reports, NEB, October, 1986
OPEC	Organization of Petroleum Exporting Countries
OECD	Organization for Economic Cooperation and Development
NGL	Natural Gas Liquids (ethane, propane, butanes and pentanes plus)
$ C	Canadian dollars
$ US	United States dollars
J	joule
PJ	petajoule
EJ	exajoule
kW	kilowatt
MW	megawatt
GW	gigawatt
kW.h	kilowatt hour
MW.h	megawatt hour
GW.h	gigawatt hour

Prefixes

Prefix	***Multiple***	***Symbol***
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

1 petajoule = 10^{15} joules

Approximate Conversion Factors

1 cubic metre	contains	6.3 barrels
		35.3 cubic feet
1 petajoule	"	950 billion British thermal units (Btu)
1 cubic metre of natural gas	"	38 megajoules of energy
1 petajoule of natural gas	"	0.95 billion cubic feet (Bcf)
1 cubic metre of crude oil	"	38 gigajoules of energy
1 kilowatt hour of electricity	"	3.6 megajoules of energy
1 tonne of coal	"	24 gigajoules of energy

Canada